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Final Programmatic
Environmental Impact Statement

Development Policy Options
for the Naval Oil Shale
Reserves in Colorado

August 1982

U.S. DEPARTMENT OF ENERGY
Assistant Secretary, Environmental
Protection, Safety and Emergency Preparedness
Office of Naval Petroleum and
Oil Shale Reserves

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Assistant Secretary, Environmental
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Oil Shale Reserves
Washington D.C. 20585

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Lead/Responsible Agency:

Department of Energy
Naval Petroleum and Oil Shale Reserves

Title of Proposed Action:

Development Policy Options for the Naval Oil Shale Reserves in Colorado

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Statement Designation:

Final Programmatic Environmental Impact Statement

Abstract:

The Secretary of Energy is requried by law to examine, from time to time, the need for development of the Naval Oil Shale Reserves. This programmatic EIS is one of the components of that examination.

This programmatic statement examines five development policy options and eight liquid fuel alternatives, one of which is oil shale on NOSR 1. The other seven are oil shale on other lands (Colony), conservation, enhanced oil recovery (EOR), offshore oil production, coal liquefaction (SRC II), biomass/alcohol and "no action at this time." The document compares the ehvironmental imapcts of two levels of production from NOSR 1 (50,000 BPD and 200,000 BPD) to those of an equivalent production (or conservation) from the other liquid fuel sources. The socioeconomic and financial impacts of the five development policy options, which range from zero to 100 percent government participation, are also evaluated. Based upon an evaluation made during the summer of 1981, the Secretary of Energy determined that the development of NOSR 1 was not warranted at that time. That "no action" decision is identified as the preferred alternative in this EIS. The development question is being periodically re-examined, however, and should the decision be made to develop NOSR 1, a site- (and process-) specific EIS would precede any development activity by DOE and would discuss environmental impacts, including cumulative impacts, in detail.

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1. SUMMARY

The Secretary of Energy is required by law, from time to time, to examine the need for the production of shale oil from the Naval Oil Shale Reserves (NOSRs). This Programmatic Environmental Impact Statement (EIS) has been prepared to assist the Secretary in that process by presenting information on the environmental and socioeconomic impacts of an oil shale development project on NOSR 1, and of a select number of alternatives. The EIS considers the environmental impacts of development of oil shale, in general, and NOSR 1, in particular, in comparison to alternatives of encouraging production from other liquid fuel resources, such as coal liquefaction, biomass, offshore oil, and enhanced oil recovery, and an alternative of conserving petroleum in lieu of shale oil production. This EIS does not attempt to evaluate the environmental impact of either the technological options or the specific sites which are available for developing the oil shale resources at NOSR 1. That evaluation will follow in a later NEPA document if DOE proposes to develop NOSR 1.

It should be noted that, due to the duration of the administrative process involved with preparing and publishing this EIS, some of the information presented here may have been overtaken by events in the very volatile and dynamic oil shale industry which occurred only recently. For example, what was only six months ago thought to be a viable, major oil shale project--the TOSCO/Exxon Colony Project--has been shut down in mid-construction. We mention this to indicate that the ongoing evaluation of the development policy for a NOSR 1 oil shale project will reflect the best information available at the time.

This EIS analyzes NOSR 1 as a candidate site for a contingency oil shale development venture. It compares the environmental impacts from the NOSR 1 range of potential production (50,000 to 200,000 BPD) with impacts from additional development of other liquid fuel options which might possibly make up for the lack of an equivalent amount of shale oil by 1990. These other options include:

- Conservation
- Oil Shale Development on Other Land
- Enhanced Oil Recovery (EOR)

- Outer Continental Shelf Petroleum (OCS)
- Tar Sands
- Coal Liquefaction
- Biomass/Alcohol.

Second, this EIS presents an environmental and financial analysis relating five generalized development policies for NOSR 1. The decision when to develop NOSR 1, and by what means, will be made by the Secretary of Energy, based on national defense requirements and other pertinent information, including the findings of this EIS (as supplemented if necessary).

NOSR 1

Located in Garfield County on the south rim of the Piceance Basin in northwestern Colorado (Figure 1-1), NOSR 1 comprises about 41,000 acres. NOSR 3, the 14,000-acre service area which abuts the east and south boundaries of NOSR 1, was set aside for potential access roads, sites for service and staging areas, reservoir areas, etc., hence is included with NOSR 1 in this EIS. It has no commercially significant oil shale resources. NOSR 1 has some 18 billion barrels of shale oil in place (in shale grades over 10 gallons per ton), of which some 2.3 billion barrels are recoverable at grades of 30 gallons per ton or more from the Mahogany Zone.

Overview

The objective of this EIS is to evaluate and compare the impacts of eight liquid fuel alternatives. In addition, five development policy options for NOSR 1 development are evaluated and compared.

In general, such comparisons are useful, but do not lead directly to any conclusions. No particular financial option leads to any overriding choice that could not be tempered thereafter by other factors. This is equally true of the environmental comparisons among liquid fuel alternatives, with the obvious exception of conservation. However, many energy sources, including conservation, may need to be developed concurrently in the national energy program to move toward some measure of energy self-sufficiency.

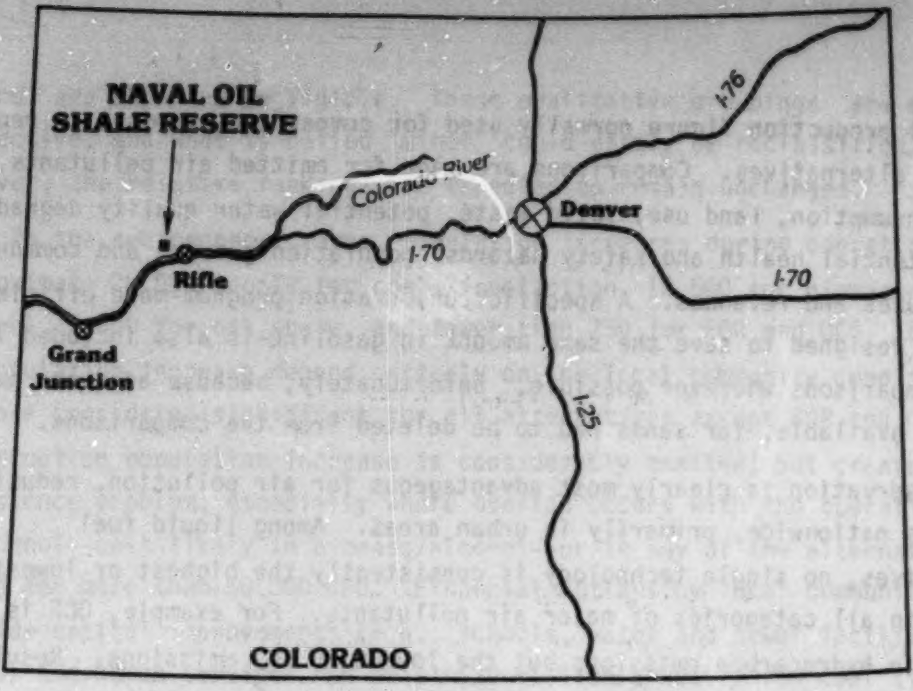

Figure 1-1. Location of Reserves

In this sense, they are not true alternatives, with the possible exception of oil shale development on other land. In addition, the isolated impact of a NOSR 1 development should ultimately be considered in a regional energy development context, since the cumulative impact effects will determine the limits of industrial growth in the Piceance Basin. Such an analysis is planned for the site-specific EIS and will be included in the mitigation plan in the NOSR predevelopment study activities, although some qualitative discussion of the issue is included in Section 5.

Brief descriptions of the eight liquid fuel alternatives and the five development policy options are provided in Section 3. The summary below compares the options and the alternatives, and incorporates certain issues raised in response to three scoping meetings held in February 1980 in Grand Junction and Denver, Colorado and public comment meetings for the draft of this EIS held in November, 1980 in those same cities.

Comparison of Alternatives

For the environmental comparisons among liquid fuel alternatives, typical plants producing 50,000 and 200,000 BPD were selected for each alternative. The larger production rate is the maximum practical rate the NOSR 1 can sustain for a 25 to 30-year plant lifetime, and represents the upper production limit that will be considered. The 50,000-BPD rate, however, is a typical production figure normally used for comparison purposes to represent all alternatives. Comparisons are made for emitted air pollutants, water consumption, land use, solid waste, potential water quality degradation, potential health and safety hazards, population growth, and community expenditures and revenues. A specific conservation program-more efficient vehicles designed to save the same amount in gasoline-is also included in these comparisons wherever possible. Unfortunately, because adequate data were not available, tar sands had to be deleted from the comparisons.

Conservation is clearly most advantageous for air pollution, reducing emissions nationwide, primarily in urban areas. Among liquid fuel alternatives, no single technology is consistently the highest or lowest emitter in all categories of major air pollutants. For example, OCS is the highest in hydrocarbon emissions but the lowest in SO_2 emissions. Results are discussed in Section 3. A more significant measure would be air quality impact rather than just emissions. This impact depends on local terrain and meteorology and on the air quality status of the region, generally requiring diffusion models to estimate impacts.

Water requirements for a 50,000-BPD liquid fuel facility are small for OCS, about 10,000 acre-ft/yr (AF/Y) for coal liquefaction, about 4,455 to 12,090 AF/Y for NOSR oil shale, (depending on the production system utilized), 19,000 AF/Y for EOR, and 3,600 AF/Y for biomass/alcohol. The impact of this water requirement will depend on the regional water availability, generally considered as a more significant problem in oil shale country than in, for example, central Illinois where the typical biomass/alcohol facility is located. Solid waste production is greatest for oil shale, running close to 20 million tons per year. Among the remaining alternatives, only coal liquefaction has any significant waste (4-1/2 million tons per year). High land use for biomass/alcohol is due to the large number of individual facilities.

A comparison of the potential for water quality degradation attributable to spills, leachates, mine drainage, and agricultural runoff shows OCS having the greatest potential, oil shale a moderate potential, and all others with minor but not negligible potential. Similarly for potential health and safety hazards, coal liquefaction is given the greatest potential, oil shale a moderate, EOR and OCS a minor, and biomass/

alcohol are shown as negligible. These qualitative groupings are quite subjective, and what is called "minor" could easily [illegible] reclassified. However, the relative rankings are expected to remain unchanged.

In the socioeconomic area, population increases during operation approximate 20,000 people for coal liquefaction, 12,500 for biomass/alcohol, 7,500 for oil shale, and fewer than 250 for EOR and OCS. Effects of population increase depend entirely on the local community conditions, and are considered significant for all alternatives except EOR and OCS. Construction population increase is considerably smaller, but creates a transience problem, especially where overlap occurs with the operations personnel--most likely in biomass/alcohol--or in any of the alternatives if sized for more than 50,000 BPD. Financial outlays by local communities to provide capital improvements (e.g., schools, water and sewer facilities, roads) and human services run about $30 million annually for coal liquefaction and biomass/alcohol, with estimated revenues about $1 million less than this amount. Revenues include ad valorem and personal property, state income, sales, and plant property taxes. However, it is generally inaccurate to assume that local communities receive state revenue allocation equal to those generated by the energy development or that state aid is provided on a timely basis. Comparable oil shale amounts are $10 million in expenditures and over $11 million in revenues. It should be noted that cost and revenue comparisons for oil shale development will vary considerably given the wide range of assumptions that are possible regarding other energy development prospects in Colorado. For the purposes of this analysis socioeconomic impacts of NOSR development in western Colorado have been assessed from two separate perspectives. First, 50,000 BPD and 200,000 BPD development options have been analyzed in isolation, assuming no concomitant development in the NOSR study area. Second, a 100,000 BPD NOSR development option has been analyzed in detail in the context of an assumed cumulative development profile in western Colorado. This latter cumulative impact analysis is presented below in Section 5, "Environmental Impacts."

For the NOSR 1, one reference production system design is used for all development policy options; therefore, all emissions and other environmental impacts are the same for all these options. There is only one significant environmental difference among the five development policy options, a socioeconomic difference due to the varying share of private property that may be directly taxed as a major source of local revenue, as mentioned above.

For evaluation of the five development policy options, standard business analysis techniques are used in conjunction with a reference oil shale production system for NOSR 1. This system utilizes conventional underground mining, three types of surface retorts, conventional upgrading, pipeline product transportation, and surface disposal of spent shale. The same production system is used to evaluate the five development policy options, as it is unlikely that the design selected for a GOCO would differ from that selected by a private entity. Since neither selection can be known at this time, the same production system is used as the basis for comparative evaluation of financial factors.

For the cases in which the industry owner earns a 15% return on investment (ROI), and the government 10% (to offset the cost of money use), the required (constant) selling price is calculated in 1979 dollars. It ranges from about $26 per barrel for the upgraded shale oil (refinery-compatible syncrude) for the fully leased-to-industry case to about $17 per barrel for the government-owned case. These somewhat artificial cases provide some insight into the downside risk of these investments, which appears small in view of current and commonly projected oil prices.

For the cases which assume an oil price scenario which increases from $25 per barrel in 1979 to $35 per barrel in 1989 and remains at $35 (in 1979 dollars) thereafter, two sets of results are derived. From an industry viewpoint, the ROI is about 20%, whether fully leased or jointly owned.

Conclusions

Based upon an evaluation made during the summer of 1981 of the information contained in the draft Programmatic EIS, state and local concerns, national energy demand, the progress of private industry in supplying conventional fuels and pursuing synthetics, the Secretary of Energy, after duly performing the evaluation as required by law, concluded that the development of oil shale on NOSR 1 was not necessary at that time.

This "no action" decision is identified as the preferred alternative in this EIS. This issue will be reexamined from time to time in the future, as will the information and analysis contained in this EIS. Should updates be necessary, draft and final supplements to this EIS will be prepared, in accordance with the Council on Environmental Quality regulations implementing NEPA.

This "no action" decision is identified as the preferred alternative in this EIS. This issue will be reexamined from time to time in the future as will the information and analysis contained in this EIS. Should updates be necessary, draft and final supplements to this EIS will be prepared, in accordance with the Council on Environmental Quality regulations implementing NEPA.

2. The Proposed Action and Its Purpose

The action evaluated in this EIS is the development of Naval Oil Shale Reserve Number 1 (NOSR 1) for the eventual production of liquid fuels from oil shale, for the purposes of assisting national defense and security. A background discussion of this proposal follows:

At the beginning of this century, President Theodore Roosevelt became concerned about a secure supply of oil for the U.S. Navy. He initiated a plan which led to an Executive Order of September 27, 1909 by President W. H. Taft, withdrawing certain public lands from general sale. This was at the time when the Navy was in the process of converting to an all oil-fired fleet and was worried about a secure supply of oil and the effects of massive increases in fuel costs. The price of ship's fuel had skyrocketed from 1 7/8 cents per gallon in 1911 to a full 3 cents per gallon in 1912.

In that year, at the request of the Secretary of the Navy, the Secretary of the Interior identified for the Navy 38,073 acres of oil-bearing public lands in California, a part of the land previously withdrawn from public sale, sufficient to ensure a supply of 500 million barrels of oil. President Taft issued an Executive Order in 1912 setting aside these lands as Naval Petroleum Reserve 1 (NPR 1), known as Elk Hills.

By 1916, the fuel cost problem was worse. The price of oil for the Navy had jumped to 5 1/2 cents per gallon and the U.S. Geological Survey (USGS) had estimated that there was no more than a 30-year supply of oil left in the U.S. at the current consumption rate. In 1914, the Navy had estimated that its requirements in wartime would triple those of peacetime, and was concerned about supplies to the civilian sector. Now, on the eve of America's entry into WWI, the problem caused great concern. On December 6, 1916, at the urging of Secretary of the Interior Lane, President Woodrow Wilson signed the order establishing NOSRs 1 and 2. The following excerpt from hearings before the Special Joint Conference of the Committee on Public Lands, December 18, 1916, discussed this event and the basic NOSR mission.

> "Chairman PITTMAN (Senator from Nevada). Are there any other naval petroleum reserves except those mentioned?

"Assistant Secretary of the Navy, Franklin D. ROOSEVELT. Those three are the only ones. There is a proposal by the Secretary of the Interior to withdraw some shale lands.

"Mr. FINNEY (DOI). It is withdrawn, Mr. Secretary - two areas in Western Colorado and Utah.

"Assistant Secretary ROOSEVELT. The shale lands, up to the present time, are not a commercial proposition as oil lands quite a different proposition. There is oil in the shale, and if it came down to a crisis and you could get no oil any other way, I suppose in time of war we could go ahead and crush the shale and extract the oil.

"Commander RICHARDSON (Bureau of Steam Engineering). In regard to the shale, you have to drive the oil off in the shape of gas, and out of a ton of shale you get 40 gallons of oil, and of that 40 gallons there is a fair percentage of gas and gasoline, so that out of that ton of shale you would probably get 24 gallons of fuel oil.

"MR. FINNEY. How much would it cost to get it?

"Commander RICHARDSON. $1.85 for the 24 gallons; and if it be in Colorado it is over a dollar to get it to the coast.

"Senator CLARK (of Wyoming). I saw something about some experiments made by people who are farsighted, I suppose, at a cost of about $4 a barrel to ship it.

"Commander RICHARDSON. $1.85 is the statement by oil men.

Several questions later:

"Senator PHELAN (of California). What is the estimated contents of those shale reserves?

"Mr. FINNEY. One billion barrels, according to the estimate of the Geological Survey.

Finally:

"The CHAIRMAN. As one of the experts of the Navy Department, would you not consider a possibility of conserving 1,000,000,000 barrels of oil, even at an expense of $4 a barrel, for future use would be a matter of interest to your department?

"Commander RICHARDSON. It was so much a matter of interest to the Navy Department that it requested the Department of the Interior to join the Navy Department in requesting the President to create a reserve of shale lands for the possible use of the Navy when the known oil fields of the country were exhausted: that it was realized that even if

> the oil fields are exhausted in a limited number of years, as the statements of the Department of the Interior indicate, the Navy must have oil available from some source."

The size of NOSRs 1 and 2 were modified somewhat by later Executive Orders, and NOSR 3 was established by an Executive Order in 1924. While less than 15 percent of NOSR 3 contains oil bearing shale, its withdrawal was considered necessary to afford working space and waste disposal areas necessary for the anticipated operations on NOSR 1.

The Secretary of the Navy did have congressional authority for the exploration, development, use and operation of the Naval Petroleum Reserves; however, he had no such authority for the NOSRs. As a result, activity at the NOSRs was extremely limited.

From 1944 to 1956, the Bureau of Mines conducted experimental work at the Rifle Oil Shale Demonstration Plant on NOSR 3 under the provisions of the Synthetic Liquid Fuel Act of 1944. In October, 1962, the Secretary of the Navy was given the same development authority over the NOSRs as he had over the Naval Petroleum Reserves, and the Department of the Interior was authorized to lease the Rifle facility, which had been idle since 1956. The facility, now called Anvil Points, was leased in April 1964. This lease expired in early 1982, and the Anvil Points facility is presently shut down, while new lessees are being sought. Oil shale from Anvil Points has also been used for research by the Laramie Energy Technology Center since 1956.

In 1976, the Naval Petroleum Reserves Production act was enacted, which defined the NOSRs as a component of the Naval Petroleum Reserves. As a result, the Secretary of the Navy had the same basic administrative authorities over the NOSRs as over the NPRs, including the authority to develop and produce and to lease. The Anvil Points facility transferred from the Department of the Interior to the Energy Research and Development Administration (ERDA).

In 1977, the Department of Energy Organization Act was enacted and transferred the authorities of the Secretary of the Navy over the NPRs and the NOSRs to the Secretary of Energy. It also transferred the authorities and functions of ERDA to the Secretary of Energy, including custody of the Anvil Points facility. Jurisdiction over the NOSRs and the Anvil Points facility remains with the Secretary of Energy at this time.

Description of NOSR

NOSRs 1 and 3 are located in Garfield County, Colorado, approximately eight miles west of Rifle, and NOSR 2 is located in Carbon and Uintah Counties, Utah, about 50 miles south of Vernal. NOSR 1 is 40,760 acres of rugged highland country in western Colorado. NOSR 3, which adjoins NOSR 1 on the east, south and west is approximately 14,130 acres in size. The elevations of NOSRs 1 and 3 range from 6,000 feet above sea level at NOSR 3 to 9,300 feet above sea level at NOSR 1. It occupies the southeast corner of the Piceance Creek structural basin where the surface rocks are of the Green River formation. This formation, which contains the oil shale deposits, is resistant to weathering and forms a spectacular escarpment where it outcrops. The high tableland north and west of the escarpment has an elevation of about 8,500 feet above sea level and is known as the Roan Plateau. The escarpment, known as the Roan Cliffs, generally marks the boundary between Naval Oil Shale Reserves 1 and 3.

At the time of its establishment, NOSR 1 was considered a prime reserve. Mahogany Zone oil shale, outcropping along the Roan Cliffs, provided visual evidence of the presence of good oil shale in a bed averaging about 80 feet in thickness. NOSR 1 is now known to contain approximately 2.3 billion barrels of oil recoverable from shale mineable by conventional mining systems.

DOE has legislative authority to explore, develop, and/or lease all the NOSRs. Before full-scale production of shale oil from the NOSRs can be initiated, however, such production must be approved by the President and authorized by a joint resolution of Congress. In addition, the Committees on Armed Services of the Senate and the House of Representatives must be consulted and the President's approval must be obtained prior to the lease of any part of the NOSRs. These approvals have not been sought or obtained to date.

Need for Development

Current law provides that the Secretary of Energy shall from time to time reexamine the need for the production of shale oil from the NOSRs. This was, in fact, the basis for initiating the extensive pre-development program which was commenced for NOSR 1 in 1977. This program was designed to develop information regarding environmental factors, resource assessment, and engineering analyses to facilitate this required assessment. In assessing this need, an issue of great significance is the unique status of the NOSRs. The Executive Orders which set aside the NOSRs also established a specific purpose for them which is quite different from that of most other Federal mineral lands: to provide a ready reserve of liquid fuels to aide in the defense and security of the nation. In 1976, the Naval Petroleum Reserve Production Act (Public Law 94-258) further clarified the purpose of the Reserves by including the following definition of national defense (in Section 201(1)): "'National defense' includes the needs of, and the planning and preparedness to meet, essential defense, industrial, and military emergency energy requirements relative to the national safety, welfare, and economy, particularly resulting from foreign military or economic actions." By including in the term national defense the concept of preparedness to meet foreign economic actions, such as the 1973 Middle East oil embargo, this Act helped establish the current pre-development program for NOSR-1.

NOSR 1 cannot be viewed as simply another parcel of Federal mineral land, such as the large oil shale holdings managed by the Department of the Interior. The unique status of the NOSRs allows the government to control their development and production in ways which either cannot be done easily, or at all, with other Federal holdings. Section 7428 of Public Law 94-258 specifically provides that:

> "Every unit or cooperative plan of development and operation... and every lease affecting lands owned by the United States within Naval Petroleum Reserve Number 2 and the oil shale reserves shall contain a provision authorizing the Secretary, subject to approval by the President and to any limitation in the plan or lease, to change from time to time the rate of prospecting and development on, and the quantity and rate of production from, lands of the United States under the plan or lease, notwithstanding any other provision of law."

In practical terms, the Federal government reserves the right to control not only development, but also production, such as by increasing or decreasing the produced quantity, or by directing that the production be sold directly to the Defense Department without entering the regular commercial marketplace, such as is presently done with some of the petroleum produced from the Naval Petroleum Reserves in California and Wyoming. These types of controls afford the nation the opportunity for an assured, dedicated, ready reserve of liquid fuels for national defense purposes. The capability to have this assured supply, to be utilized directly by the military, stockpiled, or delivered into the general marketplace, is clearly of significant strategic importance.

As has been amply demonstrated in the numerous public forums already conducted on the proposed development of NOSR 1, the issue of development is not at all clear cut. Many factors must be considered in making the determination. These factors include the strategic importance of NOSR production, the anticipated production of other oil shale lands, environmental concerns, budgetary constraints, national energy goals and policies, etc. Valid and persuasive arguments can be made on both sides of the question. Favoring the start of development work now are considerations of lead time and the proven reserves of oil shale on NOSR 1. Given the complexity and size of the effort involved, no significant production of liquid fuels products will be available from NOSR 1 until five to seven years after development is initiated. The longer the start of development is put off, the longer NOSR 1 will be incapable of effectively fulfilling its intended purpose as a strategic, ready reserve of liquid fuels. Once production starts, NOSR 1's proven reserves of 2.3 billion barrels of oil are sufficient to sustain production for decades, even at the maximum rate technologically feasible. NOSR 1 production is thus not a quick, short-lived source of liquid fuels. Once developed, however, it would provide an assured source of fuel well into the next century.

The primary argument against the start of development work now is budgetary constraints. In addition, development of NOSR 1 may generate significant environmental and socioeconomic impacts on NOSR 1 itself and on the region around NOSR 1. These impacts may be further aggravated by oil shale and other energy related development projects on lands near the

NOSRs, although these have been curtailed presently. Postponing the development of NOSR 1 would avoid any contribution to these potentially adverse impacts.

Role of this EIS in the Decisionmaking Process

This programmatic EIS is designed to fulfill the purposes established for these documents by the National Environmental Policy Act (NEPA) and the Council on Environmental Quality (CEQ) regulations implementing NEPA: (1) to help the Department reach a decision on the basic, programmatic issue of whether or not to develop NOSR 1 that is based, in part, on an understanding of the environmental consequences of this action; (2) to identify the environmental effects in adequate detail so that they can be compared to economic, social, technical and other considerations; (3) identify, at an early stage, the significant environmental issues deserving of further study, thereby narrowing the scope of later, site specific impact statements; (4) to study and describe appropriate alternatives to the proposed action; and (5) through the scoping process, public hearings and the solicitation of comments, to encourage and facilitate public involvement in decisions which affect the quality of the human environment.

It is the Department's opinion that, on a broad basis of analysis, it is the basic decision of whether or not to develop NOSR 1 which acts as the switch to turn on or off various environmental and other impacts. This Programmatic EIS presents an analysis of this broad level of impacts anticipated from the development of NOSR 1, and from a group of reasonable alternatives. Should the decision be made to develop NOSR 1, the exact mining, retorting and upgrading processes and the overall development mechanism (i.e., leasing, government owned-contractor operated facility, etc.) will lead to further refinements in the analyses contained in this EIS, and these will be dealt with via a draft and final site-specific (and technology-specific) EIS. If the decision to develop NOSR is postponed until some time in the future, the information and analyses in the Programmatic EIS will be reexamined to determine their validity at that time. Should it be deemed necessary to update the data and analyses, a supplement to this Programmatic EIS will be prepared and published pursuant to the procedures contained in the CEQ regulations implementing NEPA. In addition, the Department of the Interior (DOI) is preparing a programmatic

EIS which will describe and analyze alternative strategies for the development of a long-term federal oil shale leasing program. This EIS will include analyses of the environmental and socioeconomic impacts (including cumulative impacts) of projected shale oil development in the Piceance Basin where NOSR 1 is located. Although the NOSR 1 project is different in certain key aspects from the federal oil shale leasing program, the potential impacts from a NOSR 1 project, both site specific and cumulative, are certainly very similar to those anticipated from a shale oil project under the federal leasing program. For this reason, DOE is discussing with DOI the feasibility of including a NOSR 1 shale oil project as one of the potential development projects covered in the DOI programmatic EIS. This DOI programmatic EIS should be published in draft form during the fourth quarter of 1982. In addition, DOI is presently preparing a number of other EIS's which involve oil shale, such as the Prototype Oil Shale Leasing Supplemental EIS and the Uinta Basin Synfuels EIS. Any future NEPA compliance work for a NOSR 1 project will also be coordinated with these efforts.

Given the lack of any development plans for NOSR 1 at this time, the Department considered the soundness of publishing a final EIS for what in effect is a "no action" proposal. Although there were valid reasons and precedents for not going forward from the draft EIS, issued in September 1980, the Department felt that, on balance, the program and the public interest would be best served by revising the draft EIS according to the comments received on it and issuing a final programmatic EIS, thereby completing at least this first phase of the NEPA compliance process for the NOSR 1 project.

3. ALTERNATIVES AND COMPARISONS

The objective of this Programmatic EIS is to assess and compare the environmental impacts of the production of liquid fuels by a number of alternative means including NOSR 1 shale oil development. Should the NOSR 1 alternative be selected, then five policy options for development have been examined, and these are assessed and compared in this section. In this section, all alternatives and options are briefly described and their impacts compared. Details are provided in the sections and Appendices which follow.

3.1 LIQUID FUEL SUPPLY AND CONSERVATION ALTERNATIVES

In order to gauge the impact of the no-action policy option for NOSR 1, the liquid fuel that NOSR 1 could have provided is postulated for supply by some equivalent liquid fuel source, as noted in Section 3.2 To enable making equivalent quantitative, not merely general, comparisons, the alternatives will be represented by:

- o One or more plants of a specific type and commercial modular size that can produce 50,000 and 200,000 BPD of liquid fuel
- o A specific conservation program with savings of 50,000 and 200,000 BPD of liquid fuel
- o A specific locale for each alternative in an area capable of producing 50,000 to 200,000 BPD more than current production
- o A standard chart of environmental impacts to be calculated in the same manner for each alternative.

The typical process or program representing each alternative was selected using these criteria:

- o Feasible commercial production of at least 50,000 BPD by 1990
- o Available environmental, cost, and engineering data usable at 50,000 BPD production. Impacts and costs for 200,000 BPD production were scaled from information available at 50,000 BPD level
- o Process demonstrated at an acceptable scale
- o Environmental emissions neither excessively large nor small compared with other processes that could represent that technology alternative.

Several processes qualified for various alternatives, and final selection was based primarily on data availability. Locale was selected based upon the existence of a plant, plant design, or EIS for a particular process at that location, provided the location was thought to be representative. If none of these existed, a general location was chosen as representative of the area in which major development could take place. Representative processes selected as alternatives are shown in Table 3-1 and described in detail in the following section.

Table 3-1. Technologies Selected to Represent Liquid Fuel Alternative

NOSR 1 Oil Shale:	Underground mining, combination of surface retorting and upgrading
Conservation:	Transportation sector, light-duty vehicles
Oil Shale Development on Other Land:	Underground mining, TOSCO II retorting, Colony Project
EOR:	Steam injection, Kern County, California
OCS:	Platforms, Gulf of Mexico
Tar Sands:	Steam injection, Conoco Project, Uvalde, Texas (See text)
Coal Liquefaction:	SRC II, Morgantown, West Virginia
Biomass/Alcohol:	Grain fermentation, Central Illinois

This approach provides numerical results and, to the degree that plant selections are representative, a reasonable basis for quantitative comparisons among alternatives. To the extent that large variations in locale, pollutants, hazards, or labor force among candidates may preclude representation of any one alternative, this approach would not provide a valid basis for drawing general comparisons among alternatives. It should be noted, however, that numbers presented should be considered as relative rather than absolute indicators.

3.2 ALTERNATIVE LIQUID FUEL SOURCES - DESCRIPTIONS

The eight alternatives in Table 3-1 are discussed in terms of how and why the selection was made and the technology employed. In the following sections, major environmental impacts are plotted on a comparative basis, and the comparisons are discussed. Most descriptions and data follow in Sections 4 and 5 and in the Appendices. Because the data are extrapolated from the results of smaller-scale tests, they should be considered as approximations.

NOSR 1 Oil Shale*

The reference shale oil production system chosen for NOSR 1 is that selected early in the Predevelopment Project for interim baseline purposes. Selection of that production system is based on its suitability to the NOSR 1 resource and the availability of adequate existing data; no recommendation is implied by its selection.

The reference system uses room-and-pillar mining, three different types of surface retorts, a straightforward upgrading of the raw shale oil to a refinery feedstock syncrude, and pipeline transportation of that product. There are seven direct- and two indirect-fired retorts that handle coarse ore, and one indirect-heated retort utilizing a solid heat transfer medium for handling all the ore fines. Mine and plant are located in the northwest quadrant of NOSR 1 near Hole 18 (TRW 41x-13), about 13 miles northwest of Rifle, Colorado. The product pipeline runs from the plant site to Casper, Wyoming. Onsite surface disposal of spent shale in a suitable canyon is the reference design, although return of spent shales to mined areas is being considered.

The plant output is nominally 50,000 BPD. Maximum practical production rate on NOSR 1 is 200,000 BPD, a rate sustainable for over 20 years. The predevelopment plan, however, is based on the 50,000-BPD production rate. This EIS analyzes the reference 50,000 BPD, and integral multiples of the results for this facility will be used for larger facilities.

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* Material for this section is based on "Shale Oil Production System Reference Case Study", a report by TRW, June 1979; and Appendix B of the present document.

Conservation

There are three major conservation areas: residential and commercial buildings, transportation, and utilities. Of the three, conservation in the transportation sector has the most direct impact on liquid fuel use. Among several transportation conservation options, reduced vehicle weight was chosen to represent the conservation alternative. This option was selected since it allows impacts related to reduced gasoline consumption to be calculated without requiring assumptions to be made concerning changes in life style (such as in the case of shifts from cars to mass transit) or additional secondary environmental impacts (such as the air pollution emissions attributable to buses). This selection, therefore, provides the greatest beneficial impact to society for the reference amount of liquid fuel savings.

Only light-duty, gasoline-powered passenger cars are considered in this analysis. Total fleet emissions for EPA criteria pollutants are projected for 1990 using emission factors developed by EPA. The reduction in emissions is calculated from a national savings of 50,000 BPD of gasoline. This fuel efficiency improvement is assumed to result from a decrease in vehicle weight only, thus factors which would change the vehicle emissions, such as engine modifications or changes in vehicle use, need not be considered. The reduction in emissions which would result from using less gasoline also is calculated for the Denver area (see Section 5). Although this is a hypothetical case, vehicle weight reductions are a very plausible means of increasing vehicle gasoline mileage. It is assumed vehicle weight reduction would be accommodated during annual model year changes.

Oil Shale Development on Other Lands

The representative case selected for this alternative is the Colony Project, which utilizes the TOSCO II retorting process. A number of processes were evaluated before Colony was selected: TOSCO II, Paraho, Union B, Superior, Lurgi, Hytort, Occidental, and Geokinetics. Geokinetics, Hytort, and Lurgi were not chosen because of the small size of their demonstrations. Occidental lacked a successful large-scale test and did not meet the necessary information standards. Adequate data for Superior and Union processes were unavailable.

Colony (TOSCO II process) has completed a detailed engineering design and cost estimate and an EIS. TOSCO has operated a large 1,000-TPD semiworks plant (about 750 BPD) and has extensive information on plant characteristics. Paraho and Union are also well advanced in planning; however, Colony's estimated date of 1985 for commercial operation of a 47,900-BPD plant and the volume of available data make Colony a good choice.

The Colony Development Operation is located on the south edge of the Piceance Basin at the head of the Parachute Creek Valley. While adequate to support a 50,000-BPD facility, that property is probably not adequate to support a 200,000-BPD facility. To perform the necessary comparisons at the higher production rate, we will consider that some unspecified adjacent land will be utilized, as necessary.

The Colony production system involves conventional room-and-pillar mining and fine crushing of the ore. The TOSCO II retort utilizes hot ceramic balls to heat and retort the shale. The spent shale is cooled and wetted before disposal. The raw shale oil is upgraded before being transported to refineries by pipeline.

Enhanced Oil Recovery (EOR)

Based upon the July 1979 report from the DOE Working Group on Enhanced Oil Recovery, Unconventional Gas, and Oil Shale, and reinforced by industry estimates, it is believed only two EOR processes will produce significant quantities of oil by 1990. They are steam injection and CO_2 flooding. Currently, about 373,000 BPD of oil are produced by EOR; 250,000 by steam injection; about 100,000 by CO_2 injection; and the remainder by chemical and polymer flooding. Steam injection accounts for 99 of 196 EOR projects, with 72 of those in Kern County, California. By 1990, steam injection is expected to produce 450,000 BPD; and CO_2 injection, 400,000 BPD. Although CO_2 will have the greater rate of increase, steam injection provides greater data availability and concentration of projects, and longer period of operation. Therefore, steam injection in the Kern County area was selected to be representative of EOR technology.

Both steam soak and steam drive processes are widely used. In the steam soak process, large quantities of steam are injected into a producing well and allowed to soak into the formation. The heated oil, having more mobility, is then allowed to flow into the well. In the steam drive process, separate wells are used for steam injection and oil production.

Outer Continental Shelf Petroleum (OCS)

OCS oil production in the Gulf of Mexico was selected as the representative case for OCS production. Location of OCS production is the most significant variable in determining environmental impacts of OCS development. Impacts will vary according to production depth, weather conditions, geology, transportation modes, level of production, and requirements for onshore processing facilities--all functions of the location. Of the 15 OCS areas under consideration by the Bureau of Land Management for new leasing in the period from March 1980 to February 1985, only five are expected to produce oil at rates of 200,000 BPD or greater. These areas are the Chukchi Sea, Beaufort Sea, Navarin Basin, Gulf of Mexico, and Southern California OCS, including Santa Barbara Channel. (See Reference 19, Section 5).

The first three areas are located on portions of the Alaska OCS, characterized by such extreme conditions as severe storm activity, shear ice, moving pack ice, and permafrost. The Chukchi Sea lease should produce more oil than any of the other new leases, but due to these difficult conditions peak production is not anticipated until 1994. All of these areas are sensitive to oil spill damage. By contrast, OCS production in the Gulf of Mexico and Southern California will operate under more moderate climatic conditions. However, the Southern California OCS is in an area of high seismic risk and is also highly sensitive to spill damage. The Gulf OCS experiences frequent hurricane activity, and facilities must be designed to withstand high winds and waves. The Gulf area is moderately sensitive to oil spill damage. New production in the Gulf will peak before 1990, whereas production off Southern California will peak between 1991 and 1993.

Any one of these five areas could have been selected to represent the OCS alternative. Production in the Gulf of Mexico was selected primarily because of its earlier production potential. The general site selected is at a 400-ft depth 100 miles offshore along an extension of the Texas-Louisiana border.

Conventional fixed platforms are used for most Gulf of Mexico OCS oil production. The platforms are typically steel-jacketed structures which rest on the sea floor. From these platforms a number of wells are drilled. Three platforms would represent a 50,000-BPD case and 11 platforms would represent a 200,000-BPD case. Oil, water, and natural gas produced from the wells are separated on the platform. The oil is metered and piped to shore. Natural gas, if present, is dehydrated, pressurized, metered, and piped to shore.

Tar Sands

Most effort in tar sands is being concentrated on the Canadian deposits. In the United States, other than small-scale DOE projects, effort is being concentrated in that blurred dividing line between heavy oil and tar sands. The Getty project in the diatomaceous earth deposits of California falls into such a category.

The CONOCO South Texas Tar Sands Project is possibly the U.S. tar sands project most advanced toward commercial production. The CONOCO process is quite innovative and several patents are pending. Because of the patent situation and sensitivity of this new project's competitive position, CONOCO was able to supply only partial information. In addition, CONOCO plans only 10,000-BPD production by 1990, which does not allow for a fair comparison to be made with other, larger-scale projects.

Although some preliminary CONOCO data regarding basic technology parameters exist, insufficient information precludes any reasonable assessment of impacts due to tar sands development. Therefore, tar sands will not be included in the comparison of alternatives.

Coal Liquefaction

Five liquefaction processes were investigated, two indirect and three direct. The indirect processes are SASOL and Mobil M-gasoline. The direct processes are SRC II, H-Coal, and Exxon Donor Solvent (EDS). Although SASOL is the only process in commercial operation (South Africa), and utilizes a modified Fischer-Tropsch process, lack of available data precluded its choice. Mobil M-gasoline uses Lurgi gasification, a proven process, followed by methanol synthesis. Methanol-to-gasoline conversion is a proprietary Mobil process that has been tried only at bench scale. Moreover, environmental impacts for the integrated unit are unknown, precluding the choice of Mobil M-gasoline.

A 250-TPD (450-BPD) pilot plant for EDS is under construction, but operations to-date have been conducted only at 1/2 TPD (1 BPD). Scale-up from that level to commercial scale does not provide environmental data of sufficient confidence to merit the choice of EDS. A 3-TPD (6-BPD) unit has been operated for H-Coal and a 600-TPD (1,100-BPD) pilot plant is under construction. While this may provide adequate future data, information exists only for the 3-TPD unit. Again, the scale-up factor weighs against the choice of H-Coal.

A 50-TPD (90-BPD) pilot plant has been operated for SRC II and a 6,700-TPD (12,000-BPD) demonstration plant is in design for Morgantown, West Virginia. The scale-up factor is lowest for SRC II, more data of satisfactory confidence level are available, and Morgantown is representative of areas in which the first liquefaction plants will be built. Therefore, SRC II at Morgantown was chosen as representative of the coal liquefaction alternative.

The primary processing sections of SRC II consist of coal-slurry preparation, dissolver, refining, recycle gas treating and compression, and hydrogen recovery. Other sections include hydrogen production, gas plants, and secondary recovery system. The plant is designed with utilities included except electric power, which is purchased from a local utility.

Biomass/Alcohol

Grain fermentation to produce ethanol for use in gasohol or alcohol fuel production was selected to represent the biomass/alcohol alternative. The plants will be located in Central Illinois. Ethanol from grain was chosen because the technology is state-of-the-art and currently demonstrates better economics than production by other means of liquid fuels from biomass. Liquid fuels are produced from biomass primarily either through biological or thermochemical conversion processes. Pyrolysis techniques are under development by both Occidental Research Corporation (ORC) and Pittsburgh Energy Technology Center (PETC). Both processes produce a heavy fuel oil. ORC flash pyrolysis has been demonstrated at a

200-TPD scale in San Diego, California, using municipal solid waste as feedstock. Process and environmental data for these processes are not as readily available as for ethanol fermentation. Acid hydrolysis of cellulosic wastes and subsequent fermentation was not chosen because it is in an earlier developmental stage than grain fermentation. For these reasons, grain-to-alcohol processes are more likely to make a substantial liquid fuels contribution by 1990 than fermentation of cellulosic wastes or pyrolysis of solid waste. The Central Illinois location was chosen because raw materials such as grain and coal are close at hand, and a local market exists for agricultural byproducts. Sixty-five percent of current gasohol production is from this area.

The reference case chosen for biomass/alcohol is an energy-conserving plant design by R. Katzen Associates. The design incorporates traditional fermentation processes and demonstrated energy conservation processes, although no plant of this type has been built. The plant is designed to produce 50 million gallons of 199 proof ethanol annually (3,600 BPD) from corn. Fourteen such plants would produce an average 50,400 BPD of ethanol.

Preferred Alternative

Included among the alternatives to NOSR 1 development is the option of "no action at this time". This is the current preferred alternative for the Department of Energy based upon a host of factors evaluated in June 1981, including administration policy, the pace of industry development, national petroleum demand, potential environmental impacts and the like. The "no action" alternative does not mean, however, that all action on NOSR 1 ceases. Instead, it means no action will be taken by the government at this time to move to develop NOSR 1, although the desirability of doing so will be periodically reevaluated. Environmental baseline monitoring, meteorology monitoring and hydrology investigations will also continue in an effort to achieve the best understanding possible of the NOSR 1 ecosystem.

3.3 ENERGY EFFICIENCY COMPARISONS

Efficiency of energy supply alternatives can be calculated in a variety of ways. Three of the most often used, net energy, thermal and system efficiency, will be included in the technology descriptions in

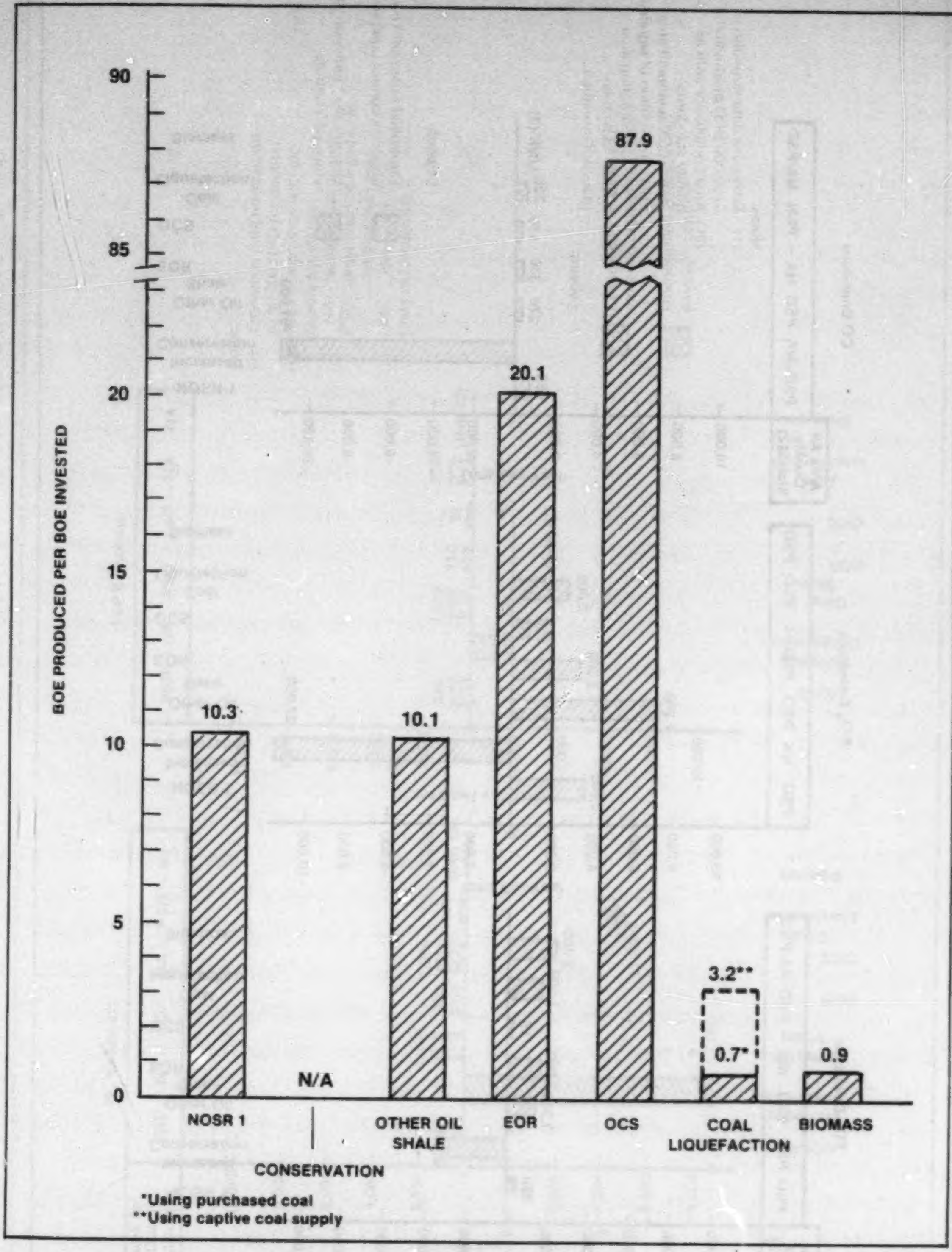
Appendix B. It should be noted that these efficiency calculations are difficult and time consuming and that some data needed may not be available for a given technology. A detailed net energy efficiency analysis for the proposal and alternatives is presented in Appendix C. Thermal and system efficiency are described in the introduction to Appendix B. Net energy efficiency calculations are presented in terms of barrels of oil equivalent (BOE) produced for each BOE invested. Others are in percentages. Net energy efficiency comparisons are shown in Figure 3-1.

3.4 ENVIRONMENTAL IMPACT COMPARISONS

Developing any of the technology alternatives discussed above will have adverse effects on the local environment where such development occurs, except for the conservation case which will have a small beneficial effect nationwide. The degree of impact will depend on factors such as emissions or water requirements directly related to the process, to the successful use of mitigating measures, and on the ability of the environment to accommodate the residual factors. In the following discussion, the environmental impacts of these alternatives are compared quantitatively wherever possible, and qualitatively elsewhere.

First, air pollutant emissions from the seven technology alternatives are compared in Figure 3-2. Emissions data from Section 5 and Appendix B have been normalized to a production level of 50,000 BPD. Data cited for the NOSR 1, conservation, other oil shale, coal liquefaction EOR and biomass/alcohol cases represent controlled emissions. However, controlled emissions data for OCS are unavailable. In this comparison the OCS rigs are assumed to be a sufficient distance from shore (as defined by USGS regulations) so as not to require air pollution controls.

Pollutant emissions are presented to enable making a gross quantitative comparison of alternatives. A better comparison would be in terms of air quality impacts which are not a function of pollutant emissions alone. Existing air quality, weather patterns, climate, terrain, and cumulative effects of multiple pollutant sources interact in a specific locale to produce the air quality impact. To indicate accurately the effect that emissions will have on the environment requires detailed, site-specific modeling. Modeling of air quality impacts would also facilitate identification of potentially non-linear relationships between production levels.



*Using purchased coal
**Using captive coal supply

Figure 3-1. Net Energy Efficiency

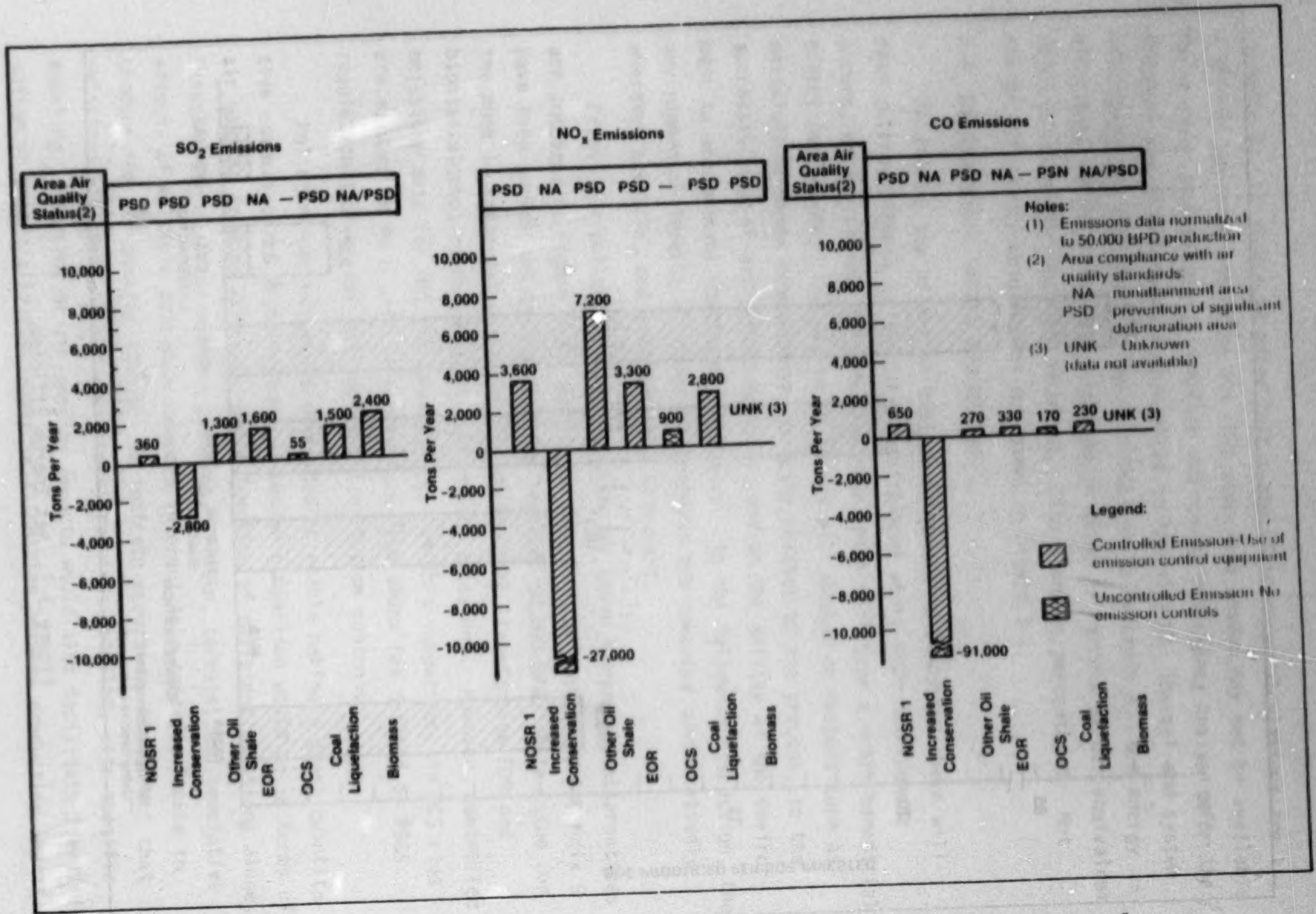


Figure 3-2. Air Pollutant Emissions Normalized to 50,000-BPD Production Level

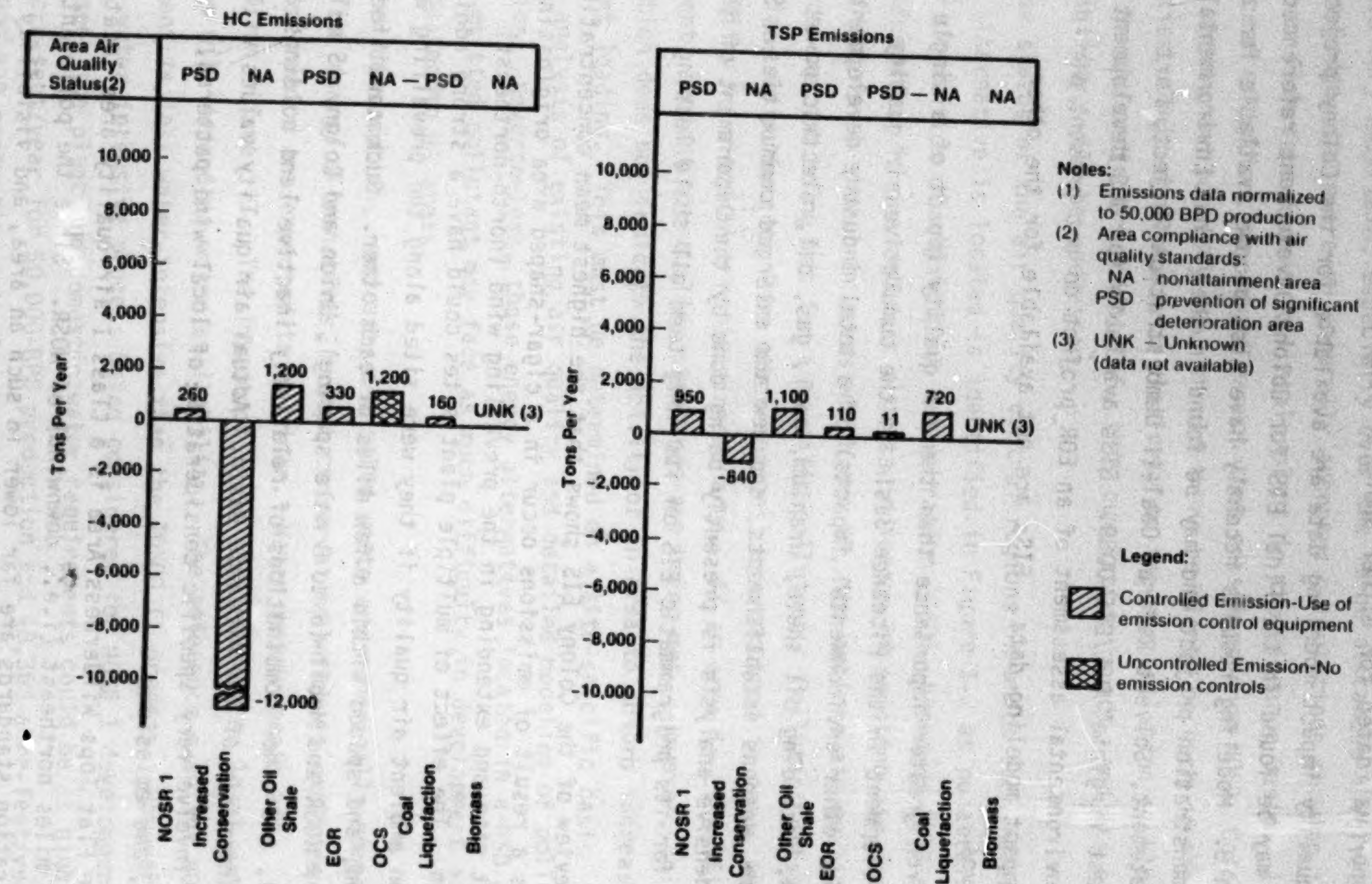


Figure 3-2. Air Pollutant Emissions Normalized to 50,000-BPD Production Level (Continued)

Unfortunately, adequate models which can represent dispersion in rough terrain such as that found in the Piceance Basin have neither been developed nor validated for either short or long distances.

Air quality impact modeling data are available for the Colony project. This data may be found in the Final EIS for Colony Development referenced in Section 5. Modeling results recently have also become available for an SRC-II demonstration project and may be found in the "Final Environmental Impact Statement, Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia" DOE/EIS-0069. EISs available for OCS development and the environmental assessment of an EOR project do not present air quality impact modeling data. EISs are not available for the other alternatives.

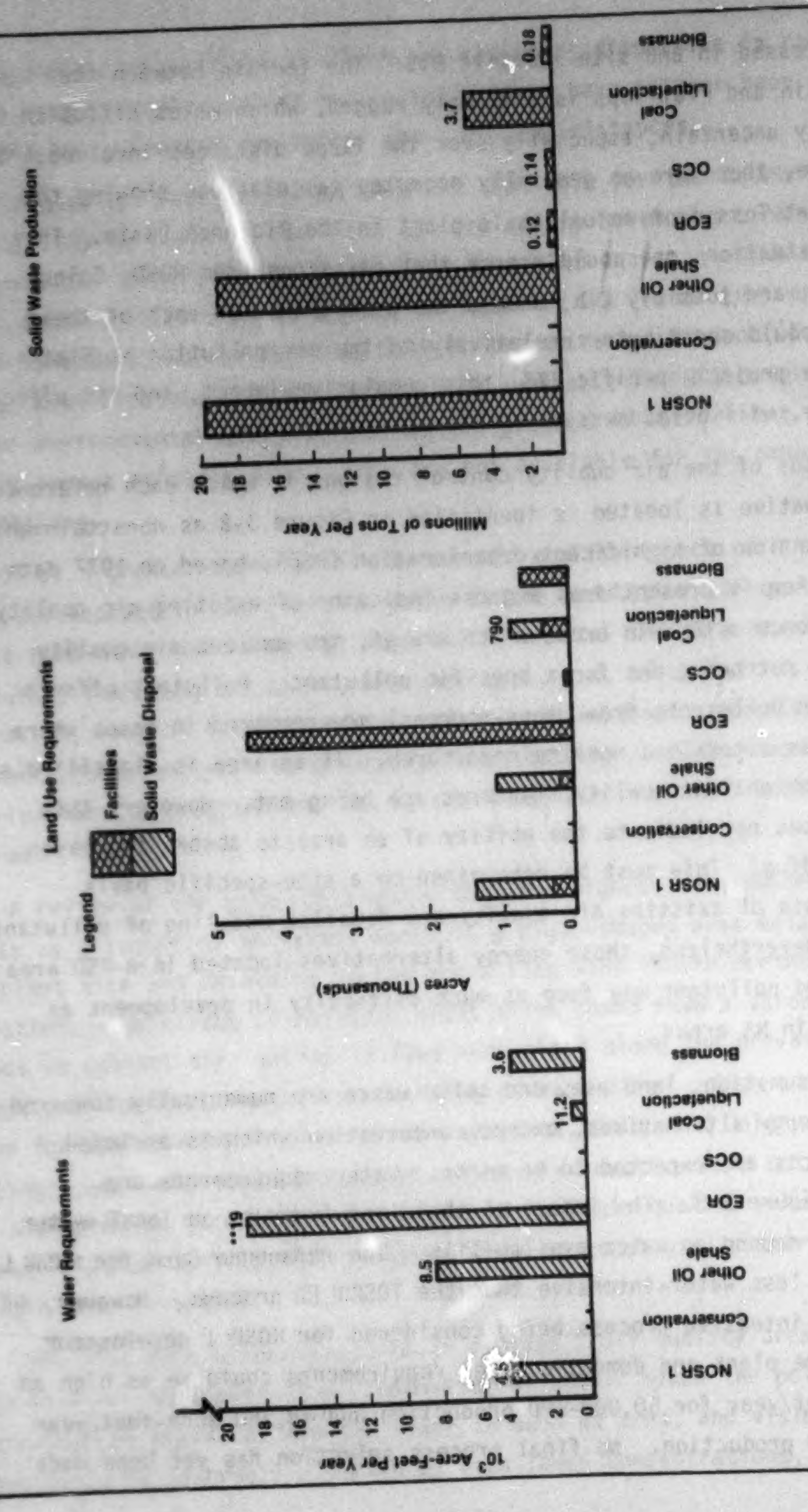
Of even greater importance than the air quality impact of a single oil shale development in the Piceance Basin is the cumulative air quality impact (and other environmental impacts) of a total industry development in the Basin, including oil shale, uranium, coal, gas, oil, electric power generation, weapons establishments, and new and enlarged communities. Such a comprehensive analysis is presently being done by the Department of the Interior for its programmatic EIS on its long term oil shale leasing program.

A review of the Colony EIS shows that the highest mean concentration levels as a result of emissions occur in a cigar-shaped area originating at the plant site and extending in the prevailing wind (north-northeast) direction. The effect of multiple plant sites could have a strong additive effect on ambient air quality if they were sited along the prevailing wind direction, and spaced within a few miles of each other. Such conditions do occur for NOSR and Mobil (6 to 8 mile spacing), Union and Colony (5 mile spacing), and other combinations of relatively inactive land holdings along the southern rim of the Piceance Basin. Actual air quality values will, of course, involve very specific consideration of local wind patterns, terrain, and emissions.

The Flat Tops Wilderness Area is a Class I air quality area located some 40 miles northeast (i.e., downwind) of NOSR. Since the pollutant concentration standards are far lower in such an area, and visibility could conceivably be adversely affected by even lower concentrations, both issues must be addressed in and site-specific EIS. The terrain between the Piceance Basin and Flat Tops is extremely rugged, which makes diffusion analysis very uncertain, especially over the large distances involved. To our knowledge, there are no generally accepted calculations showing the impact on Flat Tops from an oil shale plant in the Piceance Basin. In a worst-case situation, one could expect that emissions from NOSR, Colony, Union, Mobil, and possibly C-b, should there be plants on each of these properties, could contribute cumulatively to the air pollution at Flat Tops. In the project-specific EIS, this cumulative impact, and its effect on visibility, will be addressed.

The status of the air quality control regions in which each reference energy alternative is located is identified in Figure 3-2 as nonattainment (NA) or prevention of significant deterioration (PSD), based on 1977 data. This information is presented as a gross indicator of existing air quality at each reference site. In areas which are NA, the ambient air quality standards are not being met for a specific pollutant. Pollutant offsets (reductions in pollutants from other sources) are required in cases where a new facility is sited in a nonattainment area. If an area is classified as attainment, ambient air quality standards are being met. However, this information does not indicate the ability of an area to absorb increased pollutant loading. This must be determined on a site-specific basis through analysis of existing air quality and detailed modeling of pollutant dispersion. Nevertheless, those energy alternatives located in a PSD area for any emitted pollutant may face as much difficulty in development as those located in NA areas.

Water consumption, land use, and solid waste are numerically compared for all the energy alternatives, except conservation which is excluded since its impacts are expected to be minor. Water requirements are presented in Figure 3-3. The impact of these requirements on local water resources will depend on water availability. The reference case for NOSR 1 development is less water-intensive than the TOSCO II process. However, if the most water-intensive process being considered for NOSR 1 development were chosen, the plant and domestic water requirements could be as high as 12,090 acre-feet/year for 50,000-BPD production and 48,360 acre-feet/year for 200,000-BPD production. No final process selection has yet been made



* For reference use only. Other NOSR 1 candidate technologies being considered could require as much as 12,090 acre feet per year for 50,000 BPD production.

** Amount of water produced is equal to or greater than amount required. In some parts of Kern Co. this water may be reused for steam generation, resulting in no net water requirement.

Figure 3-3. Water Requirements, Land Use and Solid Waste Production Comparisons for 50,000-BPD Energy Alternatives

for NOSR 1, but water consumption will be an important factor in that decision.

Again, the cumulative requirements for regional development may become a controlling factor. Several regional water studies have been made,[*] generally concluding that while there is sufficient water potential to support energy growth, water retention facilities are inadequate at this time. These conclusions are dependent on controversial water need projections and are contingent on certain legal developments between the upper and lower Colorado Basin states.

The impact of such water requirements will depend on local water supply conditions. For EOR, the actual resources impact varies with the water quality of oil-bearing formations. If water produced in conjunction with oil recovery can be treated for steam production, there will not be a net requirement for water and impact should be minimal. If, however, water must be purchased, impact may be significant. Discussions with the Kern County Water Agency indicate that available water supplies are committed to current users and that additional supplies are being sought for both agricultural uses and oil production. Discussions with local regional planning commissions in central Illinois suggest that 50,000 BPD ethanol production could be supported easily if the 14 plants are dispersed throughout the area but that some areas could not support even a single 3,600 BPD plant. The SRC II project will withdraw water from the Monongahela River and could have an adverse impact on water resources during periods of low flow. Conservation and OCS should not affect water resource availability.

Land required by the reference cases is also presented in Figure 3-3. EOR will require the largest area due to well spacing requirements. Much of this land will be suitable for other concurrent uses such as grazing.

Oil shale will require sizable areas for permanent disposal of spent shale. Current surface uses of the NOSR, such as hunting and grazing, would not be possible in the immediate vicinity of the oil shale facility. Land uses not illustated in these figures include right-of-ways for pipelines and powerlines.

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[*] See, for example, "Report on Water for Energy in the Upper Colorado River Basin", U.S. Department of Interior, July 1974, or "Water for Western Energy Development - Update 1977", Western States Water Council, September 1977, or "The Availability of Water for Oil Shale and Coal Gasification," Colorado Department of Natural Resources, October 1979.

Solid wastes generated by each alternative are also illustrated in Figure 3-3. The large amount of solid wastes resulting from oil shale processing as compared to other alternatives is, of course, the spent shale. The NOSR 1 predevelopment project is considering replacement of some 80% of these solids in the oil shale mine, but this case is not presented here.

Surface disposal of solid waste requires both an adequate and an environmentally suitable disposal site.

Colony's plans for spent shale storage have been incorporated in the Colony Final EIS. NOSR terrain is similar and has a larger number of potential sites from which to choose. A description of the SRC II project indicates that acceptable sites and impermeable clays for lining the landfill are available at the proposed project location.* Solid wastes for the other alternatives are generated in smaller quantities and specific plans for these wastes are not known.

The last two environmental impacts compared, potential for water quality degradation and health and safety hazards, cannot be evaluated numerically. Therefore, they are compared in a range of "negligible" to "heavy" potential impact, and are represented qualitatively in Figure 3-4, based on the subjective evaluation of all referenced data. Water discharges are planned only for the biomass/alcohol and OCS alternatives. During normal operation, brines produced from OCS operations are not expected to adversely affect water quality. No information is available for biomass/alcohol discharges other than the assertion that fluid discharges will be treated to meet effluent standards. Whereas these direct discharges should not greatly affect water quality, runoff from spills, leaching, and other indirect sources could degrade water quality. The most serious spills would probably result from OCS operations and could have a moderate-to-heavy impact on water quality. A possibility exists that a

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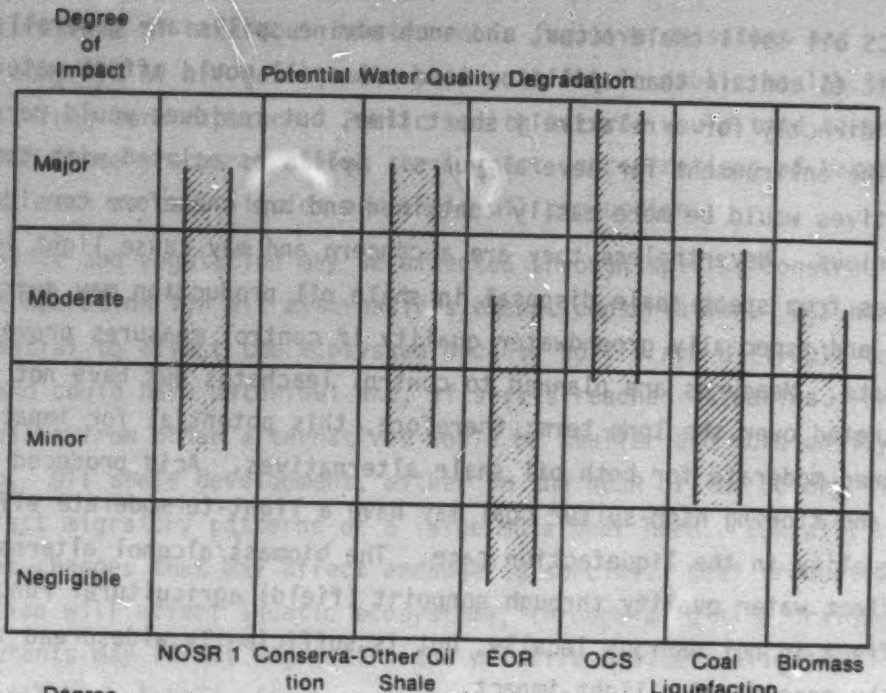
* SRC II Demonstration Project - Demonstration Plant Descriptions, July 1979.



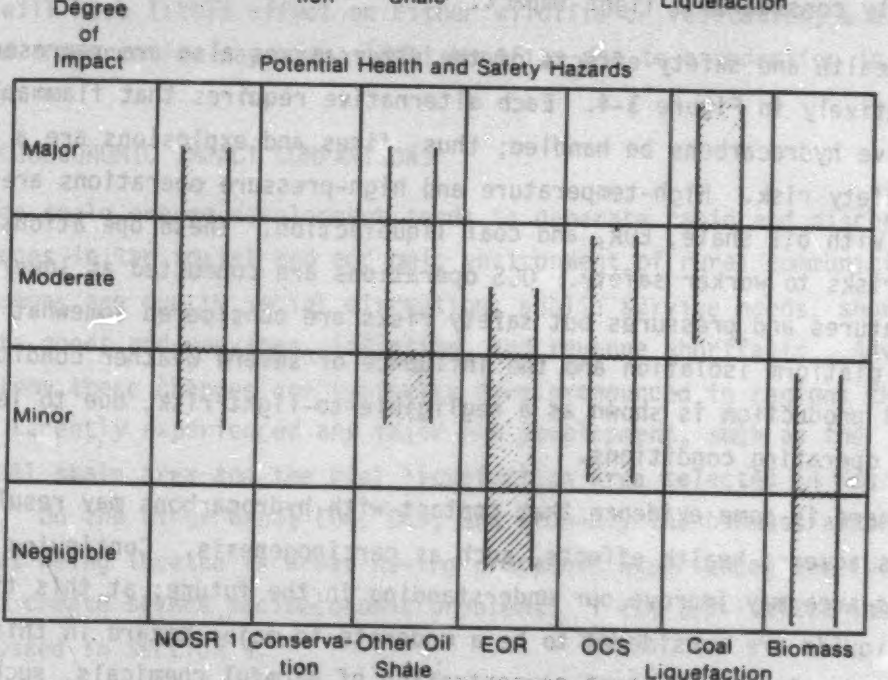


Figure 3-4. Qualitative and Subjective Comparative Assessment of the Potential for Water Quality Degradation and Health and Safety Hazards

large OCS oil spill could occur, and such marine spills are generally more difficult to contain than spills on land. A spill would affect water quality directly for a relatively short time, but residues would persist in the marine environment for several years. Spills associated with the other alternatives would be more easily contained and are therefore considered less serious. Nevertheless they are a concern and may cause light impact. Leachates from spent shale disposal in shale oil production may degrade surface and especially groundwater quality if control measures prove inadequate. Measures are planned to control leachates but have not been demonstrated over the long term; therefore, this potential for impact is considered moderate for both oil shale alternatives. Acid produced from mining and storing high-sulfur coal may have a light-to-moderate effect on water quality in the liquefaction case. The biomass/alcohol alternative will affect water quality through nonpoint (field) agricultural runoff. This effect is not serious locally, but is sufficiently widespread to be generally considered a light impact.

Health and safety effects of the alternatives also are represented qualitatively in Figure 3-4. Each alternative requires that flammable and explosive hydrocarbons be handled; thus, fires and explosions are a potential safety risk. High-temperature and high-pressure operations are associated with oil shale, EOR, and coal liquefaction. These operations pose light risks to worker safety. OCS operations are conducted at lower temperatures and pressures but safety risks are considered somewhat higher due to platform isolation and the influence of severe weather conditions. Alcohol production is shown as a negligible-to-light risk, due to less severe operating conditions.

There is some evidence that contact with hydrocarbons may result in serious adverse health effects, such as carcinogenesis. Continuing studies in this area may improve our understanding in the future; at this time, coal liquids are considered to be a moderate-to-major hazard in this regard, due to the greatest concentration of harmful chemicals, such as benzo(a)pyrene and other polycyclic compounds. Shale oil is considered to pose a somewhat lesser hazard, followed by petroleum (EOR and OCS), and finally biomass/alcohol, considered to have the least health risk due to contact with hydrocarbons.

The presence of hazardous substances in fugitive emissions and emission controls of off-gases could pose a threat to public health through low-level, long-term exposure. Public health hazards would tend to be greater for those processes having the largest concentrations of harmful chemicals, such as coal liquids and shale oil production.

Wildlife and vegetation may be affected through spills, construction, and plant operation for all alternatives except conservation. OCS has the most potential to affect the ecosystem because spills are difficult to contain and could harm waterfowl and, if spills reached estuaries, larval fish. Spills from other alternatives would be smaller and more easily contained. Oil shale development, either on the NOSR or the Colony site, could affect migratory patterns of a large mule deer herd. EOR will result in habitat changes that may affect endangered species. Coal production for liquefaction will affect aquatic ecosystems, through acid mine drainage. Air pollutants may affect vegetation and wildlife habitats slightly. Biomass will have little effect on either wildlife or vegetation, and increased conservation may have slight benefits due to a reduction in air pollution.

3.5 SOCIOECONOMIC IMPACT COMPARISONS

Large-scale energy development tends to generate rapid and discontinuous changes in the social and economic environment of rural communities. These changes are due to social disruption, public service needs, shortage of private goods and services, inflation, and revenue shortfalls. Adverse effects from these changes are typically more pronounced in regions that have not recently experienced any major new development, such as the Western oil shale area and the coal liquefaction area selected in West Virginia. On the other hand, EOR, OCS, and probably the biomass/alcohol facilities being located in areas having precedent experience, are less likely to create severe socioeconomic problems. These qualitative issues are discussed in Section 5.

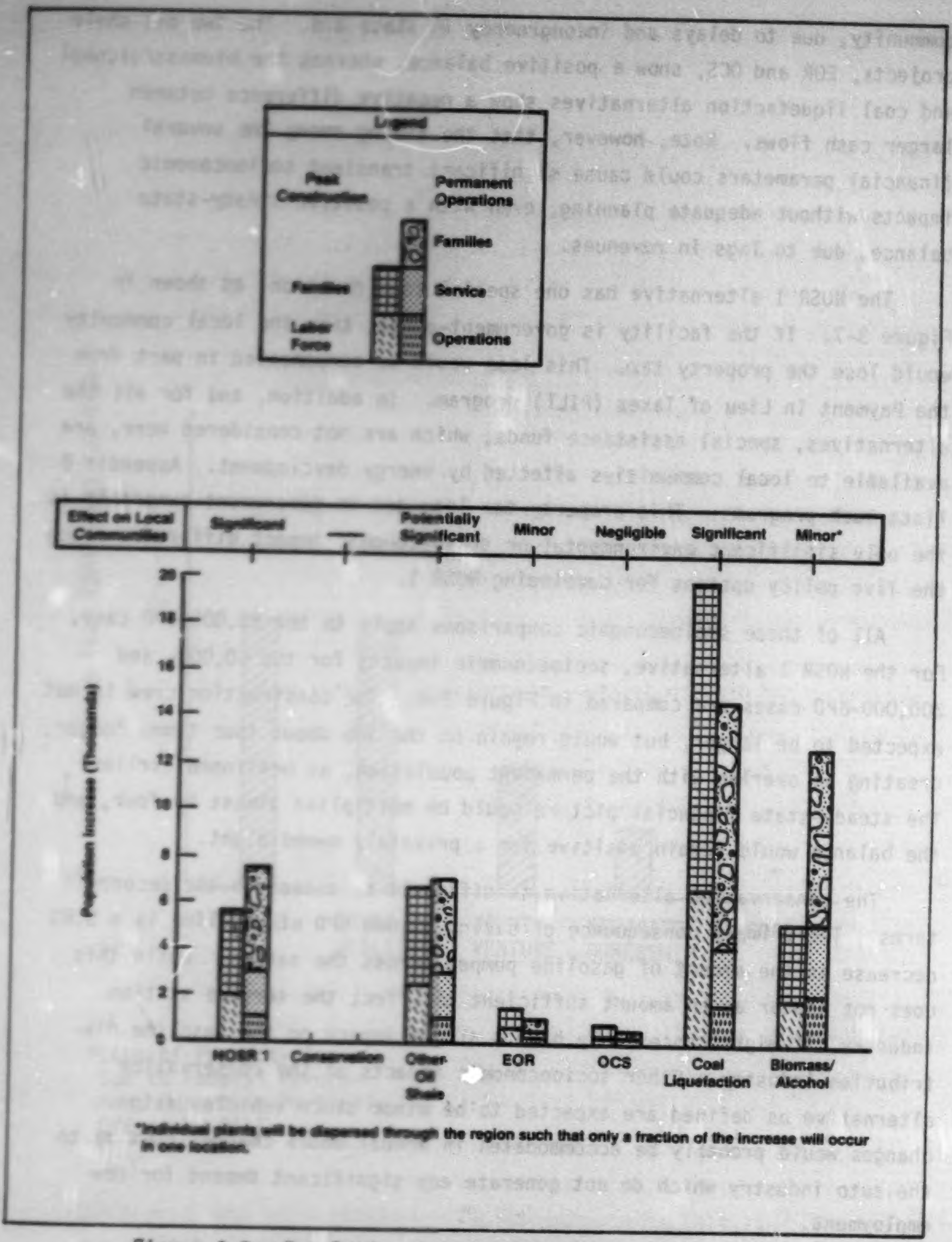
The quantitative socioeconomic factors that can be estimated from available data are compared here, based on analysis and results discussed in Section 5. Note the several important qualifications on the analysis, due to some of the necessary assumptions, which somewhat reduce the accuracy, and tend to produce worst-case results.

Population growth and financial impact on the community are the two factors that can be estimated numerically. Population growth is attributable to three factors: direct employment at the energy facility; induced employment to provide service; and the families of all those employed. Using multipliers derived from other energy development records, the population impacts have been estimated and are compared in Figure 3-5 for the 50,000-BPD case. The permanent population increase, shown by the right-hand bars, is based on the estimated plant operations personnel. This population increase is achieved a year or two after plant operations begin.

The left-hand bars show the peak construction force and its families, reached during the last two years of construction. Not shown on the bar chart is the initial buildup of the service force during construction of oil shale and coal liquefaction plants, which is hard to predict during the relatively brief construction period. The other alternatives are not expected to generate any substantial new service force, since they make a small impact in their local communities. Figure 3-5 also does not show explicitly the overlap between construction and operation employment where multiple plants are used. This occurs for EOR and OCS, but the impact is seen to be small anyway. It also occurs for the biomass/alcohol plants, where peak population could be almost the sum of the two bars for some years. However, some spreading out of the 14 alcohol plants is likely, and any one community would experience only a fraction of the indicated population increase.

Across the top of Figure 3-5 is a qualitative assessment of the population effect on the local community that relates the population increase to the existing community. A "significant" effect could have serious socioeconomic impacts unless adequate prior planning and preparation are accomplished. For example, the Colony Project has planned a new community, based on likely land use and settlement pattern analysis, to help alleviate such impacts (see Section 5).

The second qualitative comparison deals with community and state financial impacts. Figure 3-6 shows average annual public expenditures on the right-hand bars and average annual revenues on the left. Although shown side-by-side, a direct comparison of the total revenues and expenditures does not provide an accurate measure of the financial balance in the



*Individual plants will be dispersed through the region such that only a fraction of the increase will occur in one location.

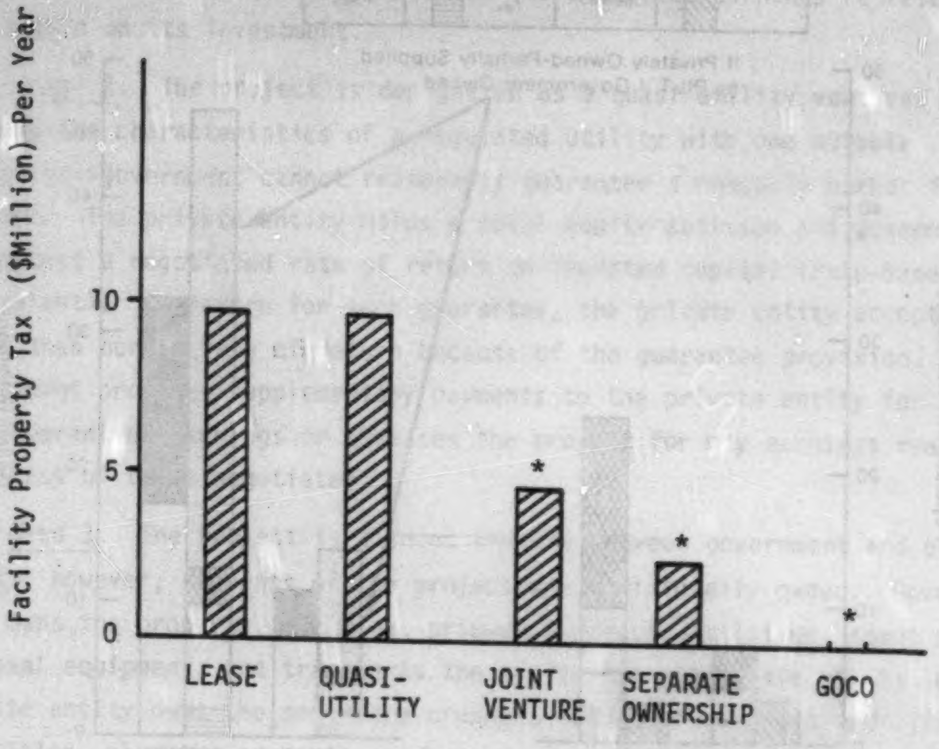
Figure 3-5. Population Impact Comparisons - 50,000-BPD Production Systems

community, due to delays and incongruency in state aid. The two oil shale projects, EOR and OCS, show a positive balance, whereas the biomass/alcohol and coal liquefaction alternatives show a negative difference between larger cash flows. Note, however, that the timing among the several financial parameters could cause significant transient socioeconomic impacts without adequate planning, even with a positive steady-state balance, due to lags in revenues.

The NOSR 1 alternative has one special consideration, as shown in Figure 3-7. If the facility is government-owned, then the local community would lose the property tax. This loss would be compensated in part from the Payment In Lieu of Taxes (PILT) program. In addition, and for all the alternatives, special assistance funds, which are not considered here, are available to local communities affected by energy development. Appendix D lists such programs. This property tax loss due to government ownership is the only significant environmental or socioeconomic impact difference among the five policy options for developing NOSR 1.

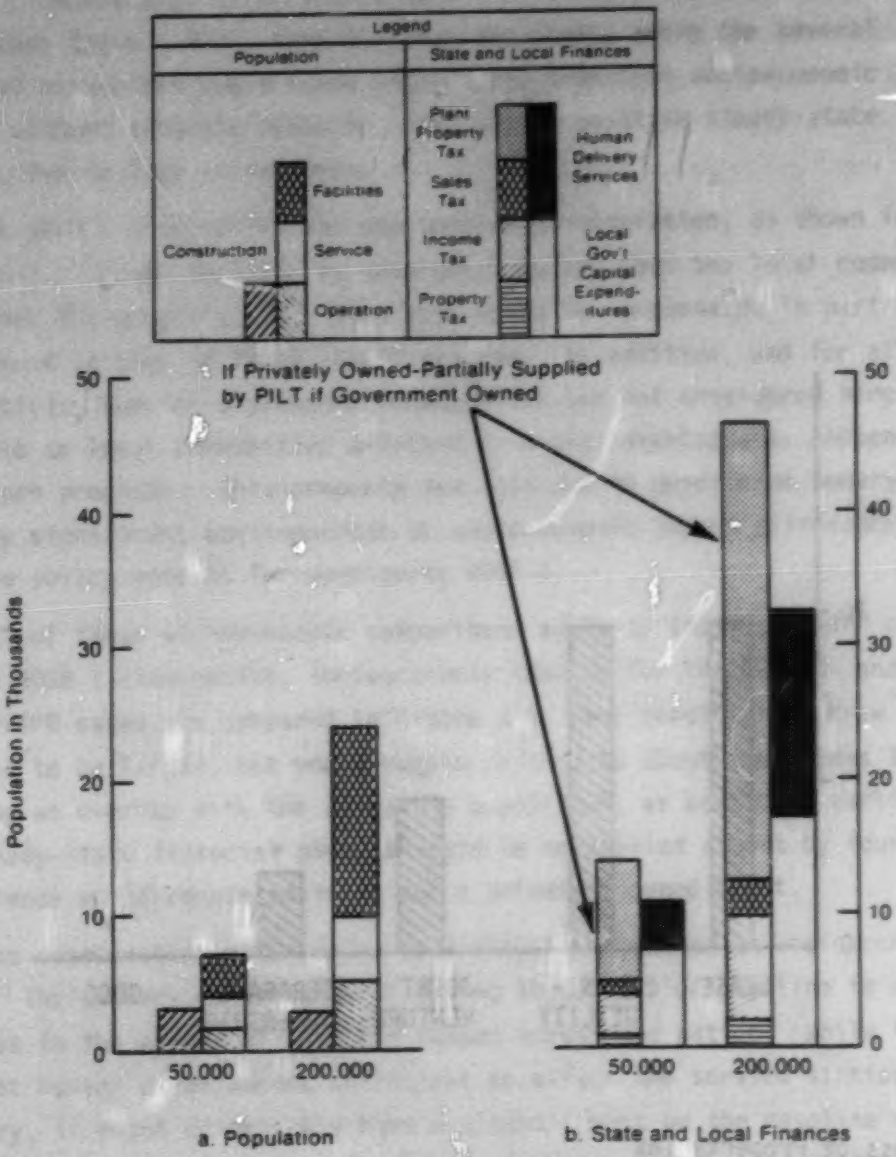
All of these socioeconomic comparisons apply to the 50,000-BPD case. For the NOSR 1 alternative, socioeconomic impacts for the 50,000- and 200,000-BPD cases are compared in Figure 3-8. The construction crew is not expected to be larger, but would remain on the job about four times longer, creating an overlap with the permanent population, as mentioned earlier. The steady-state financial picture would be multiplied almost by four, and the balance would remain positive for a privately owned plant.

The conservation alternative is difficult to assess in socioeconomic terms. The primary consequence of saving 50,000 BPD of gasoline is a 0.6% decrease in the amount of gasoline pumped across the nation. While this does not appear as an amount sufficient to affect the service station industry, it might conceivably have a slight impact on the gasoline distribution industry. Other socioeconomic impacts of the conservation alternative as defined are expected to be minor since vehicle design changes would probably be accommodated in annual model changes routine to the auto industry which do not generate any significant demand for new employment.



*Loss of Property Tax Due to Federal Government Ownership Partially Offset by PILT.

Figure 3-7. Effect of Government Ownership on Plant Property Tax for 50,000-BPD NOSR Facility



a. Population

b. State and Local Finances

Figure 3-8. NOSR 1 Socioeconomic Impact Comparisons of 50,000- vs 200,000-BPD Plant Size

3.6 DEVELOPMENT OPTIONS FOR NOSR 1

Five cases have been analyzed representing various levels of private and government equity participation in the project. The five cases analyzed are:

Case 1. The entire NOSR 1 property is leased to a private entity. The government receives bonus bid, rent, and royalty payments based upon the Department of Interior Prototype Oil Shale Leasing Program of 1974. The private entity then develops the property and holds total equity in the project. The project operations produce cash flow which the government taxes, and the private entity receives its after-tax earnings representing the return on its investment.

Case 2. The project is designated as a quasi-utility venture. It has all the characteristics of a regulated utility with one notable exception--government cannot reasonably guarantee a monopoly market for the product. The private entity holds a total equity position and government guarantees a negotiated rate of return on invested capital (rate-based equivalent). In return for such guarantee, the private entity accepts a lower than normal rate of return because of the guarantee provision. Government provides supplementary payments to the private entity for less than guaranteed earnings or assesses the project for any earnings realized in excess of those negotiated.

Case 3. The project is a joint venture between government and private entity; however, segments of the project are individually owned. Government owns the property, the mine, primary crushers, utilities, spent shale disposal equipment, and transports the ore to the plant gate at its cost. Private entity owns the secondary crusher, retort and product upgrading facilities, plus the products and byproducts. This configuration results in a 27% equity position in the total project for government, leaving a 73% share to the private entity. Government receives its ore costs plus taxes on the taxable earnings of the private entity. Private entity receives its normal after-tax earnings.

Case 4. The project is a 50-50 joint venture between government and private entity. The government receives earnings based upon its half-share equity plus normal taxes on the taxable earnings of the private entity. The private entity receives its normal after-tax earnings.

Case 5. The project is a classic GOCO venture. The government holds the total equity share and receives all project cash flows. The private entity operates the project facilities and receives a negotiated fee from the government based upon the operating and maintenance costs. This fee is taxed by the government.

No-Action Case 6. This case means non-usage of NOSR 1, and would yield no financial data for comparative purposes. It leads to consideration of equivalent liquid fuel supply alternatives, which are summarized earlier in this chapter.

3.7 FINANCIAL ANALYSIS METHODS

Financial performance of the unit production facility has been evaluated with analysis techniques commonly used by the American business community. Discounted cash flow analysis of the potential venture, time-valued investment disbursements and operating costs, and incoming revenue streams from product sales yield the project's return on invested capital, after taxes, in the usual business sense. The analysis clearly requires several assumptions regarding the future business environment during the projected economic life of the project.

The unit facility financial performance has been analyzed under two distinct scenarios:

1. A rate of return on capital employed is specified at 15% after taxes for private capital and 10% for government funds, and determination is made of the required constant selling price for the product in 1979 dollars which will achieve the specified return. This case gives some insight into the downside risk potential for investors in the project, in the event of decreasing product prices.

2. The return on invested capital is calculated assuming the following price trajectory: at the beginning of the project, upgraded shale oil is priced at $25 per barrel, reasonable in 1979 terms. The price is escalated, in 1979 dollars, by $1 per barrel for 10 years to $35 per barrel, thereafter remaining constant for the project's specified economic life. The future price of oil is obviously unknown; however, the price

trajectory chosen is considered conservative from the perspective of world oil price evolution during recent years.

3.8 NOSR 1 SHALE OIL PRODUCTION FACILITY

Financial parameters used for the 50,000-BPD facility (in 1979 dollars) are:

Capital Costs	$ Millions
Facility and equipment	875
Spare parts and miscellaneous	30
Reserve and working capital (where applicable)	250
Other accumulated expenses	140
Total Capital Cost	1,295

Operating Costs	$ Millions/year
Mining	39
Taxes, insurance, licenses, and contingency (where applicable)	15
Other operating expenses	47
Total Operating Cost	101

Investment requirements and operating costs typify estimates of these factors by private and government analysts over the past two or three years, normalized to 1979 dollar values. Investment and project revenue schedules are based upon current estimates of construction schedules, startup production rates, and long-term average fraction of design production capacity.

3.9 FINANCIAL RESULTS - SUMMARY AND DISCUSSION

Results of the analysis of the five financial options appear in Figures 3-9, 3-10 and 3-11.

Figure 3-9 shows the required selling price for the product (Scenario 1) to produce a 15% after-tax return on invested capital to the private sector and a 10% charge on government funds to offset the government's borrowing costs. The highest selling price is required by the leasing case and is about $26 per barrel, which approximates the composite world oil price in late 1979. In all other cases, the required selling price is

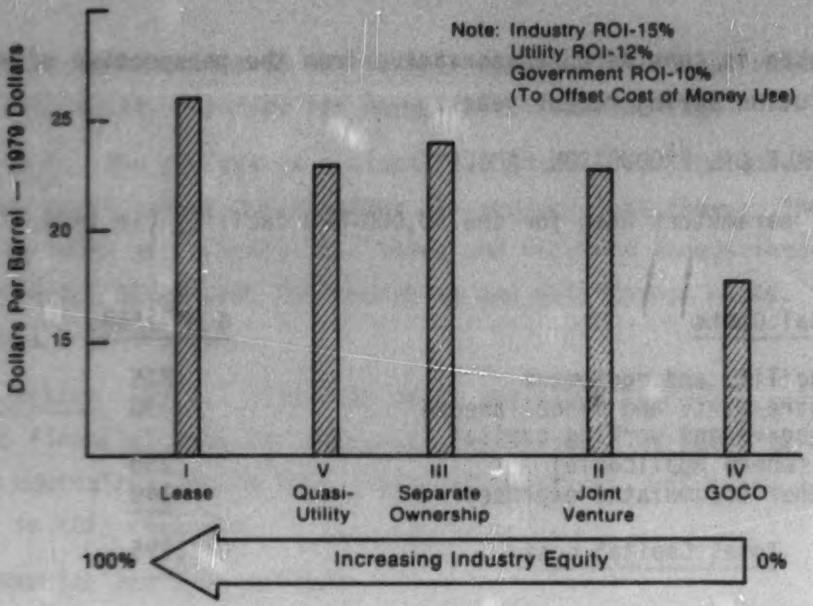


Figure 3-9. Required Selling Price to Meet Target ROI

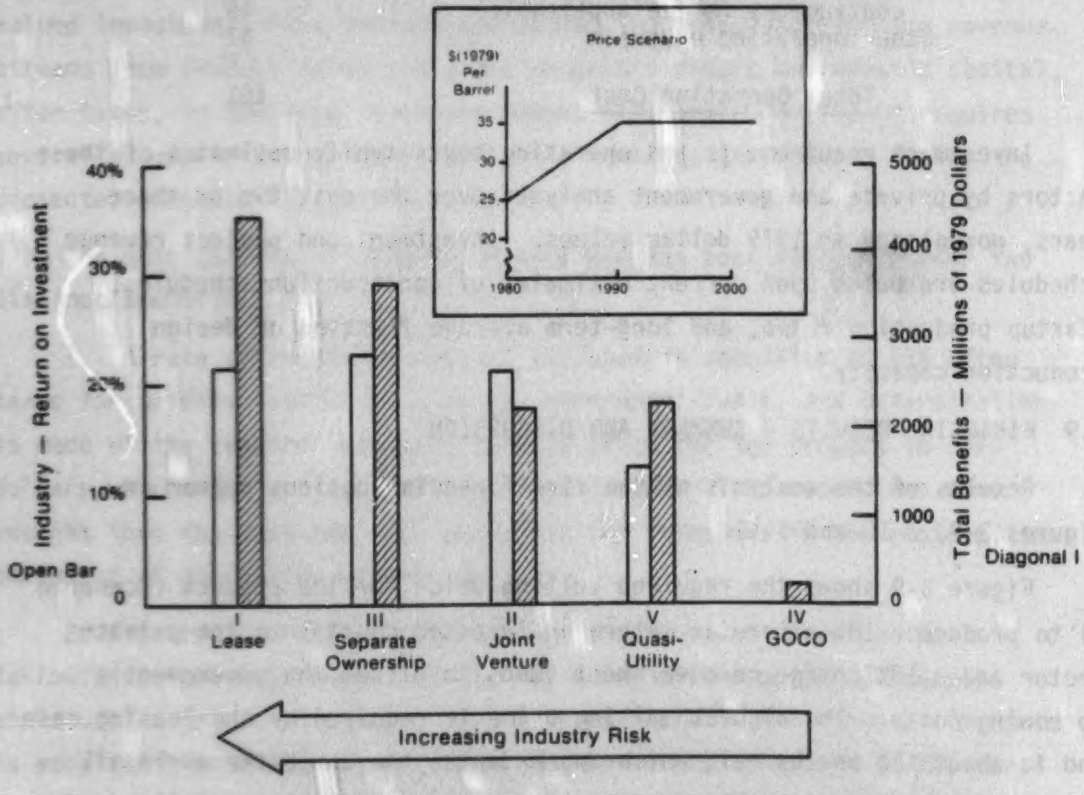


Figure 3-10. Private Sector Results Based on Market Price Scenario

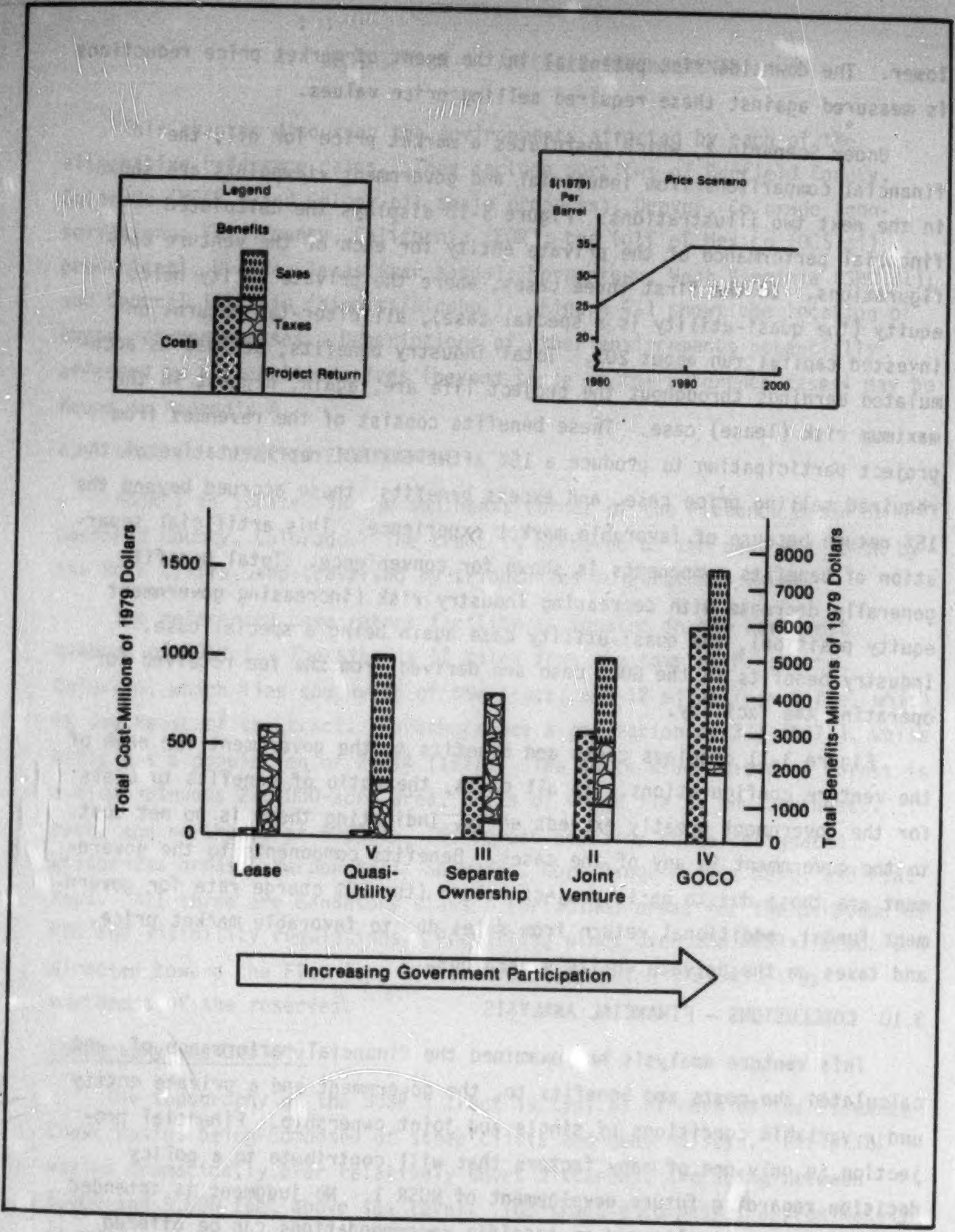


Figure 3-11. Government Cost and Benefits Based on Market Price Scenario

lower. The downside risk potential in the event of market price reductions is measured against these required selling price values.

Under Scenario 2, which postulates a market price for oil, the financial comparisons from industrial and government viewpoints are shown in the next two illustrations. Figure 3-10 displays the calculated financial performance of the private entity for each of the venture configurations. In the first three cases, where the private entity holds equity (the quasi-utility is a special case), all after-tax returns on invested capital run about 20%. Total industry benefits, defined as accumulated earnings throughout the project life are, again, highest in the maximum risk (lease) case. These benefits consist of the revenues from project participation to produce a 15% after-tax ROI representative of the required selling price case, and excess benefits, those accrued beyond the 15% return because of favorable market experience. This artificial separation of benefits components is shown for convenience. Total benefits generally decrease with decreasing industry risk (increasing government equity position), the quasi-utility case again being a special case. Industry benefits in the GOCO case are derived from the fee received for operating the facility.

Figure 3-11 displays costs and benefits to the government for each of the venture configurations. In all cases, the ratio of benefits to costs for the government greatly exceeds unity, indicating there is no net cost to the government in any of the cases. Benefits components to the government are those due to basic project return (the 10% charge rate for government funds), additional return from sales due to favorable market price, and taxes on the private entity's earnings.

3.10 CONCLUSIONS - FINANCIAL ANALYSIS

This venture analysis has examined the financial performance of, and calculated the costs and benefits to, the government and a private entity under variable conditions of single and joint ownership. Financial projection is only one of many factors that will contribute to a policy decision regarding future development of NOSR 1. No judgment is intended regarding these results and no specific recommendations can be offered based only on the financial performance factors.

4. DESCRIPTION OF AFFECTED ENVIRONMENTS

This chapter discusses the environments affected by each of the alternative reference cases. They include portions of Garfield County, Colorado (NOSR 1 and Colony oil shale projects); Denver, Colorado (conservation); Kern County, California (EOR); the Gulf of Mexico (OCS oil production); Uvalde, Texas (tar sands); Morgantown, West Virginia (SRC II); and Central Illinois (biomass/alcohol). Figure 4-1 shows the location of these reference cases. Descriptions of other environments potentially affected by these alternatives (beyond those of the reference cases) may be found in Appendix A.

4.1 NOSR 1: AFFECTED ENVIRONMENT

NOSR 1 is located in the southeast corner of the Piceance Basin in Garfield County, Colorado. The tract is bordered on the east and south by the Roan Cliffs, and traversed by tributaries to Parachute Creek.

The referenced case retort facility is located in the northwest quarter of NOSR 1. The site is 11 miles from the town of Parachute, Colorado, which lies southwest of the tract, and 12 miles from Rifle, which is southeast of the tract. Parachute has a population of 377 (1977), while Rifle has a population of 2,244 (1977). The White River National Forest is a discontinuous 238,000-acre area, parts of which lie to the southeast, east, and northeast of NOSR 1. The forest contains three designated wilderness areas: Maroon Bells-Snowmass, Gore Range-Eagles Nest, and Flat Tops. All three are mandatory Class I (pristine) areas for the purposes of PSD and visibility regulations. Prevailing winds over the NOSR 1 tract are directed toward the Flat Tops Wilderness area, which lies 43 miles northeast of the reserves.

Topography and Geology

The topography of the NOSR 1 tract is typical of much of the Piceance Creek Basin, being composed of steep cliffs and deep valleys. Elevation varies dramatically over relatively short distances, averaging between 8,000 and 9,000 feet above sea level. The tract encompasses approximately 41,000 acres.

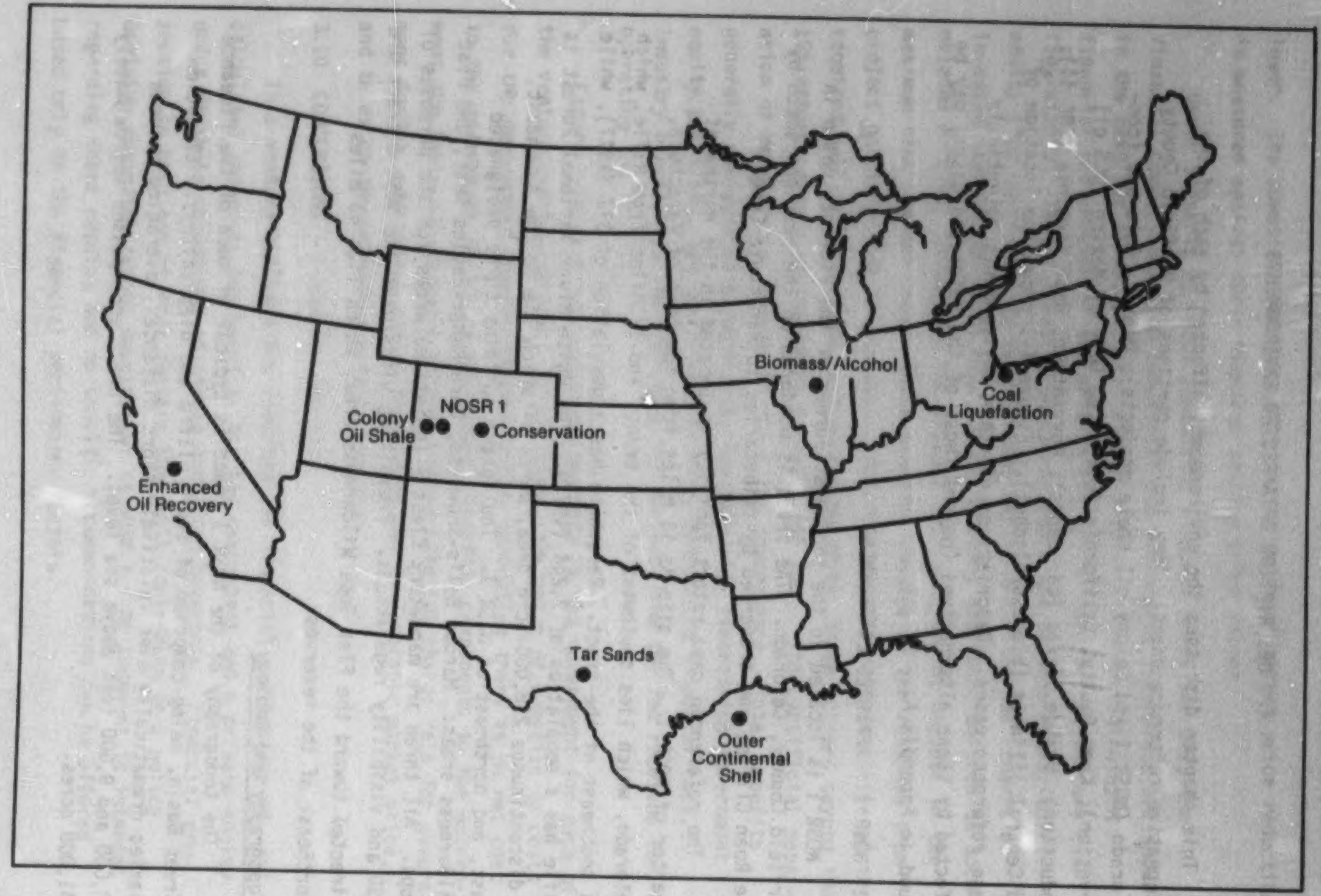

Biomass/Alcohol
Coal Liquefaction
NOSR 1
Colony Oil Shale
Conservation
Enhanced Oil Recovery
Tar Sands
Outer Continental Shelf

Figure 4-1. Location of Alternative Reference Cases (U.S. Map)

Oil shale occurs in three major zones. The rich Mahogany zone (approximately 60 feet thick) interfaces with the upper and lower lean Mahogany zones. Five low-grade zones of oil shale occur above the Mahogany zone, and two below it. Overburden above the Mahogany zone ranges from zero at the East Fork Parachute Creek to 1,200 feet in the northwest portion of the tract. Oil shale of the greatest thickness and quality is found in the northwest corner of NOSR 1.

The Piceance Basin contains prominent systems of faults that cross the basin about 20 miles northwest of the NOSR 1 property. Regularity of structure contours within the Reserve suggests that large faults are probably not present in the NOSR. One small fault is located on the NOSR in an extreme northwest area of the Reserve. This fault is 1,500 feet long on aerial photos and is not considered a hazard to development; however, it may provide a channel for the flow of water into underground shale mining operations in the vicinity of the property. No restrictions are anticipated on mine locations due to faults in the area. NOSR 1 is an area of low seismic potential. There are no active faults on or near the NOSR property. Only minor damage would be anticipated from distant earthquakes. No restrictions are foreseen in mine placement due to faulting or unstable slopes on the property. Soil creep, rock fall, and rare landslides present the main categories of geologic hazard on NOSR 1.[1]

Meteorology and Climatology

The climate is semiarid in the Piceance Basin, with annual precipitation ranging from 12 to 24 inches. Temperatures range from approximately 10° to 90° F.

Meteorological data at the NOSR site have been collected since December 1979 from a monitoring system located near the north central part of the property. Monitoring has been conducted for wind speed and direction, temperature, humidity, and rainfall. Table 4-1 summarizes meteorological data collected during 1980 and 1981. Wind speeds generally average under 10 mph, with peak wind gusts reaching 40 mph. Wind direction

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[1] TRW Energy Systems Planning Division, Long-Range Utilization of NOSR-1: Photogeologic Evaluation of Hazards, for U.S. DOE, September 1980.

TABLE 4-1. SUMMARY OF METEOROLOGICAL MONITORING DATA FOR 1980 AND 1981*

PARAMETER	QUARTER							
	1st		2nd		3rd		4th	
	1980	1981	1980	1981	1980	1981	1980	1981
WIND SPEED (mph)	8.9	8.5	7.9	9.8	7.9	8.0	8.8	9.7
10 Meters	8.9	8.5	7.9	9.8	7.9	8.3	8.8	9.7
25 Meters	10.2	10.3	8.8	10.7	9.1	10.3	9.3	11.1
50 Meters	10.1	10.8	8.1	10.8	10.1	9.7	10.5	12.0
WIND DIRECTION (degrees)								
10 Meters	178	210	182	195	201	174	169	193
25 Meters	190	197	184	186	188	174	206	194
50 Meters	192	(b)	185	181	156	177	178	198
TEMPERATURE (^{o}F)								
10 Meters	23.6	17.6	41.8	52.3	ND(b)	59.0	30.4	31.3
50 Meters(a)	--	27.5	--	53.2	--	59.1	33.7	30.9
RELATIVE HUMINITY (%)	54.5	54.6	39.1	38.1	39.2	47.1	43.8	60.1
RAINFALL (inches)	0.54	0.03	0.11	0.9	0.9	2.99	0.85	1.6

*All Values are averages per quarter. Rainfall values and averages of total rainfall

(a) Monitoring started in November 1980

(b) No data due to sensor malfunction

is predominantly from the south to southwest, but there are periods when the winds head from an east to northeasterly gradient.[2]

The wind direction parameter is one of the most critical in performing dispersion modeling analysis, and based on the available data, air pollutants would be transported primarily toward the north to northeast, with the most sensitive receptor in this direction being the Flat Tops Wilderness area. Based on wind data at this single point, there probably would be little, if any, direct air quality impacts on the towns of Rifle or Parachute from development on the NOSR.

Hydrology and Water Quality

Surface waters in NOSR 1 include the Corral Gulch, Trapper, and Northwater Creeks in the northern half of the reserve; and Ben Good Creek and the Parachute East Fork in the south. All of these creeks flow in an east-west direction and meet several intermittent tributaries before reaching Parachute Creek to the west of the tract. Water flow through the reserve is minimal during the late summer, fall, and winter. Parachute Creek is part of the Upper Colorado River Basin system. Water flow is extremely variable throughout the system and subject to salinity problems. Groundwater in the NOSR 1 area is the subject of ongoing predevelopment work. Early results indicate that the aquifers are isolated by geologic barriers from groundwater outside the tract.

The Colorado River will probably serve as the water supply to the NOSR 1 project. The river is fed by the Green, Yampa-White, and Lower Green Rivers, which drain a total of 29,504,000 acres.[3] The flow of the Colorado varies considerably by season. Competing water users, including NOSR, other energy projects, and agriculture, will be permitted to use this resource only in accordance with state water rights laws. The upper Colorado is a popular trout fishing river.

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[2] TRW, Air Quality and Meteorological Monitoring at Naval Oil Shale Reserves, 1980 Report June 1981.

[3] Regional Environment-Energy Data Book: Rocky Mountain Region, p. 274.

Preliminary analysis of surface water quality data reveals that NOSR surface waters are of generally high quality. Specific conductance ranges from 380 to 1,250 mhos (at 25°C) with most values lying in the 300-600 mhos range. This indicates generally good to excellent quality. Total dissolved solids concentrations generally fall in the vicinity of 400-500 mg/l.[4] Stream sediment loadings are highly variable. Of the parameters which have been measured, only nitrate and nitrite consistently exceed water quality standards. This is probably due to livestock usage on the NOSR. Cadmium and mercury levels have occasionally exceeded standards.[5] Cursory review of other major and trace element parameters does not reveal any outstanding values other than for strontium which is relatively high. High levels of strontium also have been reported elsewhere in the oil shale region.

Hydrologic studies of NOSRs 1 and 3 have shown the presence of four persistent water-bearing zones. They are referred to as zones pending a more precise delineation of their upper and lower limits. The uppermost zone includes facies of the Uinta Formation and the upper part of the Parachute Member of the Green River Formation, which also contains a leach zone readily identifiable on outcrop. This zone, called Zone 1, probably is a more or less unconfined water table zone. Zone 2 is located at the A-Groove, the lean zone overlying the Mahogany Zone. Zone 3 is located in the vicinity of the B-Groove, the lean zone at the base of the Mahogany Zone. Zone 4 lies 100 to 200 feet below the base of the R-6 oil shale strata that underlie the B-Groove. The topographic surface water drainage divide which separates NOSR streams from the Piceance Creek drainage to the north also is a groundwater divide. The groundwater system underlying NOSRs 1 and 3, for about the first 2,000 feet in depth, is nearly an island unto itself, having very little interaction with the rest of the Piceance structural basin.[6]

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[4] TRW Energy Engineering Division, "NOSR Baseline Characterization Report-1980", Draft, July 1981.

[5] Junkin, P.D., Private communication, July 1981.

[6] TRW Energy Systems Planning Division, "Interim Hydrology Report for NOSR 1", for U.S. Dept. of Energy, September 1980.

Preliminary analysis of NOSR groundwater quality indicates the water is of high quality. Specific conductance ranges from 460 to 895 mhos (at 25°C) with means of 569, 652, 685, and 719 for Zones 1 through 4, respectively. Total dissolved solids range from 290 to 1,060 mg/l with means of 350, 384, 382, and 408 for Zones 1 through 4.[7] While there may be a slight increase in conductance and dissolved solids with depth, there is considerable variability in the data and overlap of ranges. Of the parameters measured, three sometimes exceeded the Safe Drinking Water Standards. Arsenic and lead occasionally exceeded standards in Zone 1 only. Fluorides exceeded the standard in Zones 2, 3, and 4 and average concentrations increase with depth.[8]

Air Quality

NOSR 1 is located in a region of generally excellent air quality. Occasional short-term violations are reported in the region as the result of natural dust (total suspended particulates) and hydrocarbon aerosols (non-methane hydrocarbons). Although Garfield County in which NOSR 1 is located is in attainment for the National Ambient Air Quality Standards (NAAQS) primary standards, parts of Mesa County to the south violate standards for TSP.

Ambient air quality data were collected at NOSR during the 1980 and 1981 summer programs. Monitoring was conducted for total suspended particulates, sulfur dioxide, ozone, and trace elements monitoring for inhalable particulates was added to the 1981 Program. The results of the 1980-1981 monitoring program[9] indicated that air pollutant concentrations are well below both federal and Colorado standards with the exception of ozone. A summary of the data is presented in Table 4-2. The low levels are due primarily to the absence of major emission sources on the site or in the region.

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[7] TRW Energy Engineering Division, NOSR Baseline Characterization Report-1980, draft, July 1981.

[8] Junkin, P.D., Private communication, July 1981.

[9] TRW, Air Quality and Meteorological Monitoring at Naval Oil Shale Reserves, 1980 Report, (draft), May 1981.

Table 4-2. Summary of Baseline Air Quality Data at NOSR 1
(All values in micrograms/cubic meter)[1]

POLLUTANT/AVERAGING PERIOD	MEASURED LEVELS 1980	1981	FEDERAL STANDARDS	COLORADO STANDARDS
Suspended Particulates 24-Hour Maximum	30	37	260	150
Sulfur Dioxide 24-Hour Maximum	13	69	365	365
3-Hour Maximum	44	118	1,300	700
Ozone 1-Hour Maximum	206	265	240	160
Lead Quarterly Average	0.013	0.006	1.5	1.5

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[1] Monitoring periods: June 25 to September 21, 1980, and June 25 to September 20, 1981.

Particulate emissions on the site consist primarily of fugitive dust raised by vehicles traveling on unpaved roads, and from construction of adjacent tracts. Table 4-3 presents particulate data collected during the 1981 program and includes both total and inhalable particulates. The inhalable particulates include only those of 15 microns or less, and the majority (58 percent) of the particulates sampled fall within this size range. The maximum value recorded in 1981 was 37 mg/m^3 compared to 30 mg/m^3 in 1980. The geometric mean for the 1981 data was 24 mg/m^3 and 18 in 1980. The higher values may be attributable to drier soil conditions, as there was very little snow from January to May in 1981 and very little rain until the latter part of the summer. The particulate levels on the average were higher in July than in either August or September. In addition, there was increased activity on adjacent oil shale tracts which produced particulate emissions visible from the NOSR. Although insufficient data prevent calculation of an annual geometric mean, the mean of 24 mg/m^3 would not be expected to be much higher on an annual basis, as higher levels are expected during the summer months.

Sulfur dioxide levels, although low in comparison to ambient standards, were significantly higher in 1981, possibly attributable to several factors: increased exhaust emissions from the diesel generator, which consumed more than twice the amount of fuel in the first month, compared with the generator used the previous year; modification to the sampling instrument as a result of EPA recommendations, making the instrument more accurate; and higher ambient sulfur dioxide levels due to growth in the area. The maximum 24-hour average recorded in 1981 was 69 mg/m^3, compared to the standards of 365 mg/m^3. The maximum three-hour average was 118 mg/m^3 compared to the standards of 1,300 and 700 mg/m^3 for federal and state, respectively.

Ambient ozone levels exceeded both federal and state standards in 1981, while in 1980 only the more stringent state standard was exceeded. The federal standard was exceeded on four separate days and the state standard on 12 days, the same as the previous year. The maximum value recorded was 265 mg/m^3 compared to 206 mg/m^3 in 1980. High ozone levels are not unusual in the Rocky Mountain region due to elevation and intense solar radiation that is a contributing factor to ozone formation. Although

Table 4-3. Total Suspended Particulates and Inhalable Particulates Data*

SAMPLE DATE	TOTAL SUSPENDED PARTICULATES (μg/m^3)	INHALABLE PARTICULATES (μg/m^3)	INHALABLE PARTICULATE PERCENTAGE OF TOTAL
6-27-81	37	29	78
7-3-81	37	26	70
7-9-81	21	13	62
7-15-81	28	9	32
7-21-81	21	13	62
7-27-81	22	9	41
8-2-81	22	11	50
8-8-81	25	18	72
8-14-81	19	12	63
8-20-81	23	17	74
8-26-81	22	12	55
9-1-81	13	8	62
9-13-81	23	13	57
9-19-81	22	13	59
GEOMETRIC MEAN	24	14	58

*1981

the ozone standards have been exceeded, the oil shale region has not been classified as non-attainment area due to the limited amount of data collected over the last few years. For permitting of new sources in the region, both the EPA and the state would require the use of best available control technology for all sources of volatile organic compound emissions which are precursors to ozone formation.

Sampling for trace elements was performed to establish a baseline of such elements that may be contained in shale and surrounding soils, as during construction and plant operations these elements may be found in fugitive dusts. With the exception of lead, no air quality standards exist for these elements, although many have potential environmental and health effects. The baseline concentration of the elements analyzed in 1980 and 1981 is shown in Table 4-4. All the elements are at low concentration, with some of them below the minimum detectable limit. The low levels are due primarily to the low ambient levels of total suspended particulates, since the trace element concentrations are a function of particulate levels. Many of the 1981 trace element values are higher due to higher particulate levels than in 1980.

Table 4-4. Baseline Trace Element Analysis

ELEMENT	1980 LEVELS (μg/m^3)	1981 LEVELS (μg/m^3)
Aluminum	4.79	<0.03
Antimony	<0.0003	0.0004
Arsenic	0.0008	0.0013
Beryllium	<0.0001	0.0052
Bismuth	0.0002	0.0002
Boron	0.0016	0.3680
Cadmium	0.0005	0.0043
Calcium	7.55	1.78
Chromium	0.047	0.002
Copper	0.068	0.014
Germanium	<0.003	<0.031
Iron	0.63	0.22
Lead	0.013	<0.006
Magnesium	2.30	0.67
Mercury	0.0002	0.0030
Molybdenum	0.0007	0.0098
Nickel	0.003	0.001
Selenium	<0.0003	0.0005
Tin	<0.0003	0.0009
Titanium	0.79	0.02
Vanadium	0.002	0.003
Zinc	0.036	0.015

Biological Resources[10]

In 1980 a number of biological studies were performed on NOSR 1. These studies included a survey of vegetation, big game, endangered species, small mammals, coyotes, birds, and fish. Highlights of these studies are presented below.

Eleven native vegetation types and two other landscape units have been mapped on the NOSRs. They are Aspen Woodlands, Douglas-Fir and Spruce/Fir Forests, Pinyon-Juniper Woodlands, Mixed Mountain Shrublands, Juneberry/Big Sagebrush Shrublands, Big Sagebrush/Snowberry Shrublands, Mountain Grasslands, Moist Meadows, Indian Ricegrass Communities, Sparsely Vegetated Slopes, Scree Pavement, Disturbed Areas, and Agricultural Areas. The predominant vegetation types on NOSR 1 are the Aspen Woodlands and Big Sagebrush/Snowberry Shrublands. On NOSR 3, the Mixed Mountain Shrublands and Pinyon-Juniper Woodlands are the most common vegetation types.

The big game survey showed that portions of NOSR 1 are used heavily by mule deer and elk as a summer range. Mule deer utilization is highest on the ridge between Northwater and Trapper Creeks in the northwest part of the tract. Elk utilization in the summer is also high in this location, as well as in the southern part of the tract around the east fork of Parachute Creek. While these parts of the tract are heavily utilized, use is variable on NOSR 1 and is low compared to use of the winter range. This is due to the wide availability of summer range which results in a more dispersed big game distribution pattern in the summer months. Information from the Bureau of Land Management indicates that the lower elevations on NOSR 3 serve as critical winter range for mule deer and winter range for elk. In addition to providing habitat for large game and other wildlife, the NOSRs provide forage for cattle from spring through fall and for sheep all year long. NOSR 1 is primarily a summer range and NOSR 3 is winter range.

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[10] TRW Energy Engineering Division, NOSR Baseline Characterization Report-1980, Draft, July 1981.

A total of 29 species of mammals were observed on the NOSRs between 1975 and 1980. In addition to mule deer and elk, black bears, a puma, coyotes, beaver, and bobcat were observed, along with many smaller mammals including several species of squirrels, voles, ground squirrels, weasels, mice, and rabbits.

Sixty-five species of birds were observed on the NOSRs from 1975 through 1980. Among these species are included the golden eagle, five species of hawks, two falcons, and two species of owl. Two species of grouse have also been observed. Census transects indicated that the most common birds on NOSR 1 are the Vesper Sparrow, Blackcapped Chickadee, Gray-headed Junco, and Mountain Bluebird. Each was most common in the Snowberry, Aspen, Doublas-Fir, or Serviceberry habitat type, respectively.

The Northwater, Trapper, and East Middle Fork drainages each support dense populations of native Colorado River cutthroat trout (Salmo clarki pleuriticus), rather than a hybrid variety as was thought earlier. The Colorado cutthroat is considered a threatened species under Colorado legislation, although it is not federally listed. The East Fork of Parachute Creek and First Anvil Creek support dense populations of brook trout (Salvelinus fortinalis) and native Colorado cutthroat trout.

No endangered animal species were identified on NOSR. Two federally listed bird species, the peregrine falcon and the bald eagle, have been sighted along the Colorado River to the south of the property. Several endangered species of fish occur in the Upper Colorado River. These include the Colorado squawfish and the humpback chub, which are on the national endangered species list. The humpback sucker and bonytail chub, also found in the Colorado, are on the Colorado list compiled by the American Fisheries Society. While not found on NOSR, populations could be affected by water depletions or pollutants entering the river.

The endangered plant species survey showed the presence of one species on the federal list. It is a grass, Festuca dasyclada, which occurs on exposed ridges and scree slopes where the substrate is a coarse shale rubble. Three other plants on the property are found on proposed endangered lists. They are Astragalus lutosus, Aquilegia barnebyi, and

Sullivantia purpusii. Sullivantia has recently been dropped from consideration as an endangered species. All four of these plant species occur in limited microhabitats on the NOSR 1 property.

The Colony oil shale project is adjacent to the NOSR tract on the western side. Additional information on the area may be found in Final EIS: Proposed Developments of Oil Shale Resources by the Colony Development Operation in Colorado, BLM, 1977. The Colony information is generally applicable to the NOSR tract due to the close proximity of the projects. Union Oil has a tract contiguous to NOSR 1 and immediately south of Colony. Mobil is adjacent to Union and is located southwest of NOSR 1. Neither Mobil nor Union has information available.

4.2 CONSERVATION: AFFECTED ENVIRONMENT

Conservation of fuels used for transportation would have a general positive effect on national air quality. The discussion below gives a brief summary of the nation's air quality based on attainment/nonattainment of the National Ambient Air Quality Standards (NAAQS). It is followed by a description of the Denver, Colorado area, which is used as a reference case for assessing impacts of the conservation alternative.

National Air Quality

The Clean Air Act Amendments (1977) required states to report to the EPA which areas had achieved the NAAQS and which were in violation. The results indicate that photochemical oxidant standards are the most widely violated of the NAAQS. They are formed when hydrocarbons combine with nitrogen oxides in the presence of light. The primary NAAQS for photochemical oxidants are violated in most of the northeast, in California, in metropolitan areas, and in some rural areas throughout the country. Stationary sources of hydrocarbons and automobiles are major contributors to the problem. Carbon monoxide, emitted primarily from automobiles, is concentrated in urban areas. Non-attainment areas occur in scattered pockets throughout the United States. Nitrogen oxides are chiefly emitted by fossil fuel-fired plants and automobiles. The only large areas in violation of NO_x standards are in southern California, though urban areas tend to violate standards on a local level. Violations of standards for total suspended particulates are scattered throughout the urban-industrial centers of the East, and over larger areas in the drier western states. Natural sources are major contributors in the West, while fossil fuel combustion is a chief source in the East. Sulfur dioxide is a major emission of coal burning operations. Violations of standards occur in scattered locations throughout the coal-burning areas of the East and in certain western states (e.g., Arizona, Nevada, Utah, and California).

Ambient air quality is determined by a number of factors, including natural and man-made emission sources, and by meteorology and topography. General descriptions of the national air quality must be understood to have numerous exceptions on the local level. With this understanding, it can be said that air quality tends to be worse in the more industrialized East, particularly for pollutants which are chiefly produced in the urban community. However, most metropolitan areas in all parts of the United States are in violation of carbon monoxide and photochemical oxidant standards.

Denver

Denver, Colorado is a consolidated city-county covering a 95.2-square mile area. It sits at the eastern edge of the southern Rocky Mountains at an elevation of approximately 5,000 feet. Denver is a major metropolitan area with a population density of 5,090 persons/square mile and a civilian labor force of 222,827.[11]

The topography of Colorado is characterized by dramatic relief, ranging from 3,350 to 14,433 feet above sea level. Denver lies in an irregular plain which suddenly rises to a complex mountain system west of the city.

Winds generally are out of the south or southwest averaging 9.1 mph. Moisture-laden air moving from the west loses most of the moisture before reaching the eastern slopes of the Rockies, leaving Denver with an annual average precipitation of only 13 inches. Snowmelt provides the chief source of surface water in the state. Mean monthly temperatures range from 33°F in January to 74°F in July, with extremes ranging from -10° to 90°F.

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[11] Demographic statistics from County and City Data Book 1977, Bureau of the Census, U.S. Dept. of Commerce.

The metropolitan nature of the Denver area has combined with topographic and meteorological characteristics to produce an area of relatively poor air quality. Denver violates the primary NAAQS for CO, TSP, and photochemical oxidants. Part of the county violates NO_x primary standards. Transportation is the largest source of these emissions.[12]

Several national forests encompass large portions of Colorado's mountainous areas. Since they are located west of Denver, prevailing winds generally would carry pollutants generated in Denver away from the protected forests. However, there are several mandatory Class I areas (pristine) in northern Colorado.

4.3 COLONY OIL SHALE PROJECT: AFFECTED ENVIRONMENT[13]

The site of the proposed Colony oil shale project is at the southern edge of the Piceance Basin in Garfield County, Colorado. It lies immediately west of the NOSR 1 tract. The project is located in the upper canyon of Parachute Creek, a tributary of the Colorado River. (Several tributaries of Parachute Creek drain the NOSR 1 tract.)

The Piceance Basin is a large depression or downwarp which trends northwest, having a relief of 4,000 feet. Steep valleys and cliffs characterize the region. (Also, see discussion of geology presented under NOSR alternative in Section 4.1). The area has a relatively low seismic potential, with only minor damage anticipated from distant earthquakes. Oil shale is found in the Parachute Creek member of the Green River Formation.

The site is located at the eastern perimeter of an area subject to air stagnation episodes. Grand Junction, 40 miles to the southwest of the project, experiences one of the highest frequencies of inversion in the United States. Garfield County, where the site is located, is an attainment area for all NAAQS pollutants.

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[12] Source: 1976 National Emissions Report, National Emissions Data System of the Aerometric and Emissions Reporting System, EPA, August 1979.

[13] Information source: Final EIS: Proposed Development of Oil Shale Resources by the Colony Development Operation in Colorado, BLM.

Surface water is subject to high salinity problems. Groundwater tends to be high in dissolved solids. Big game hunted in Garfield County include deer, elk, and black bear. Several species of fish are harvested from Parachute Creek and its tributaries. Endangered/threatened species are known to occur in the general area, including the black-footed ferret and the peregrine falcon. Four fish species in the Colorado River are on federal or state endangered species lists. Archeological studies have shown no evidence of prehistoric use at the project site, although areas surrounding the site have yielded prehistoric finds.

A more detailed description of the environment affected by the proposed Colony project may be found in the "Final EIS: Proposed Development of Oil Shale Resources by Colony Development Operation in Colorado", BLM.

4.4 ENHANCED OIL RECOVERY IN KERN COUNTY, CALIFORNIA: AFFECTED ENVIRONMENT

Kern County in southern California contains a variety of physiographic types. Moving from east to west, it contains the western portion of the Mojave desert, followed by the Sierra Nevada mountains, the southern end of the San Joaquin Valley, and the slopes of the coastal ranges on the western side of the county. Oil production is largely confined to the western half of the county.

The area is dry, receiving an average of 7.3 inches of rain annually. Most streams and lakes are intermittent. The increased use of groundwater and water from other counties has made Kern one of the leading agricultural counties in California. Major crops include alfalfa hay, potatoes, grapes, and cotton. Cattle grazing is a major land use in the county. Surface and groundwater in Kern are generally of poor quality due to high concentrations of dissolved solids. The solids are largely deposited due to natural causes.

Parts of Kern County are designated non-attainment areas for carbon monoxide, photochemical oxidants, sulfur dioxide, and particulates. The poor air quality is the result of emissions from oil field operations and urban-industrial sources combined with frequent inversion episodes. Kern County as a whole is not heavily populated, having an average population density of 43 persons per square mile. Bakersfield, the largest city in the county, has a population of 77,000. Vegetation in western Kern County consists mostly of grasses and low scrubs, capable of surviving the dry climate. Several endangered species occur in Kern County. The California Condor may be found in the western part of the county, but does not nest there. The San Joaquin kit fox and the blunt-nosed leopard lizard live in the San Joaquin valley. Increased agricultural land use has been the primary threat to the habitats of these two species. Non-endangered fauna in the area include the coyote, cottontail rabbit, and the kangaroo rat.

Further information on Kern County can be found in the Final EIS for Petroleum Production at Maximum Efficient Rate: Naval Petroleum Reserve No. 1, DOE, August 1979; and the Final EIS for the Elk Hills/SOHIO Pipeline Connection Conveyance System, Department of the Navy, September 1977.

4.5 OCS OIL PRODUCTION IN THE GULF OF MEXICO: AFFECTED ENVIRONMENT

The Gulf of Mexico is subject to tropical storms from late summer to early fall, and the probability of damaging cyclones is fairly high each year. The predominant current is the Yucatan, which enters the Yucatan Strait, flowing clockwise through the central and eastern gulf, and exiting through the Florida Strait. Surface currents change with the season. Unstable bottoms and shallow gas deposits may represent geologic hazards to oil well development.

While commercial and recreational fishing are important, shrimp, crab, and oyster are the most valuable fishing industries. Pollution is a problem at the mouth of the Mississippi and near major ports. Coastal estuaries, deltas, swamps, and marshes are extremely productive biologically, and several endangered species occupy the marine and coastal environments. Approximately 2,000 shipwrecks are believed to lie in the Gulf, two of which have been designated as national historical sites.

4.6 SRC II IN MORGANTOWN, WEST VIRGINIA: AFFECTED ENVIRONMENT

Morgantown, West Virginia is located in northern part of the state in the Appalachian plateau. It is situated on the Monongahela River, which is in the Ohio River Basin. Topography of the surrounding area consists of steep wooded hills and narrow valleys.

Morgantown has a population of approximately 30,000 people. The work force numbers 10,177, of which 48% are government workers. The outlying population is sparsely distributed, largely located in the stream valleys. Resources in the area include coal, timber, gas, and oil. Primary land uses include small farms and woodland.

The climate is humid, with 44 inches of precipitation annually. Winds generally are from the south or southwest. Thunderstorms occur 40 to 50 days in the year and frequently cause local flooding. (Up to six inches of rain in a 24-hour period have been recorded throughout the northern part of the state.)

Vegetation consists of grass pastureland and shrubs in the valleys, and hardwood and coniferous trees on the hills. Small game and deer inhabit the less populated areas. Although area surface water is abundant, industrial and municipal pollution, as well as acid mine drainage, have seriously damaged water quality. The air quality in Monongalia County, where Morgantown is located, does not violate the primary NAAQS. However, parts of Marion County, adjacent to Monongalia, do not meet the primary standards for particulates. Two Pennsylvania counties, Green and Fayette, are directly to the north of Monongalia. Green County violates the primary standard for photochemical oxidants, while Fayette County violates the primary standards for photochemical oxidants, SO_2, and particulates.

Geologically, Morgantown is located in the Appalachian geosyncline. The geology consists generally of a thick sequence of sedimentary rocks resting on a layer of igneous or metamorphic rocks. The gross stratigraphy of the area is made up of the Dunkard Group of the Pennsylvanian-Permian Age, beneath which lies the Monongahela Group of the Pennsylvanian Age. The three main producing coal seams are the Pittsburg, the Sewickley, and the Waynesburg, which lie in the Monongahela group. The coal is high volatile bituminous (fixed carbon less than 69%), and is relatively high in sulfur (1.5 to 4%). Ash content is also high, 8 to 12%.

Additional information on this area and surrounding region can be found in the Draft Environmental Impact Statement, Solvent Refined Coal-II Demonstration Project, Fort Martin, West Virginia, DOE, May 19, 1980, the Final EIS: Alternative Fuels Demonstration Program, ERDA, 1977; or the Regional Environment-Energy Data Book: Southern Region, DOE, 1978.

4.7 BIOMASS/ALCOHOL IN CENTRAL ILLINOIS: AFFECTED ENVIRONMENT

Like much of the mid-continental region, central Illinois is characterized by expanses of flat, highly agriculturalized land. It experiences cold winters and warm summers. Frequent transitory changes in temperature and humidity occur as winds carry in the climatic characteristics of surrounding regions, unrestrained by the flat topography.

Agriculture uses approximately 90% of the available land in most counties. Chief crops in Illinois, in order of importance, are corn, soybeans, wheat, hay, and oats. Among the states, it is the leading producer of soybeans, and in some years the leading producer of corn. The fertile, deep soils produce 83 bushels of corn per acre. Livestock products include hogs, beef cattle, and milk.

The socioeconomic characteristics of central Illinois may make the area better able to absorb the impact of limited energy development as compared to Colorado. Central Illinois has a larger potential supply of workers and greater availability of support services than does the Piceance Basin.

Central Illinois receives approximately 38 inches of rain annually. Artificial drainage of croplands is commonly practiced. Major surface waters include the Illinois and Sangamon Rivers. Non-point sources of pollution, such as agricultural runoff and mining drainage, have resulted in damaged water quality in many parts of the state. Groundwater sources are limited, and many areas in central Illinois depend on artificial reservoirs for industrial and municipal water.

Several counties in central Illinois do not meet the primary NAAQS particulates and photochemical oxidants. Standards for sulfur dioxide and/or carbon monoxide are violated in certain populous areas, such as Peoria.

Coal-bearing sequences of rocks from the Pennsylvanian System underlie 36,806 square miles of Illinois. Large mines have operated in central Illinois for many years, producing chiefly from the Illinois No. 6 seams. The coal is primarily high volatile C bituminous.

Further information on central Illinois may be obtained from the Regional Environment-Energy Data Book: Midwest Region, DOE, 1978. In addition several Final EISs which pertain to the area have been prepared by DOT. They include:

EIS: I-72 and F.A. 412;

EIS: Route 142, Menard and Sangamon Counties; and

EIS: Highway F-408, Illinois.

4.8 REFERENCES, CHAPTER 4

"Air Quality and Meteorological Monitoring at Naval Oil Shale Reserves, 1980 Report", (draft), TRW Energy Engineering Division, May 1981.

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"Draft Conceptual Design of Shale Oil Production Systems for NOSR 1", TRW, September 1979.

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"Final Environmental Statement for the Proposed Five-Year OCS Oil and Gas Lease Schedule: March 1980-February 1985", BLM, USGS, 1979.

"Long Range Utilization of NOSR-1: Photogeologic Evaluation of Hazards", TRW Energy Systems Planning Division, September 1980.

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"Water Resources Data, 1977, Colorado", USGS.

"Water Resources Data, 1978, Colorado", USGS.

5. ENVIRONMENTAL IMPACTS

This section discusses the environmental impacts of reference cases for alternative means of producing liquid fuels. The alternatives discussed include: oil shale development on NOSR 1; increased conservation; oil shale development on lands other than NOSR 1; enhanced oil recovery; Outer Continental Shelf oil production; tar sands development; coal liquefaction; biomass/alcohol; and no action to develop NOSR 1. In order to place alternatives on a comparative basis and to enable discussion of specific environmental consequences, reference cases were chosen for each technology alternative. Descriptions of the reference cases are presented in Section 3 and Appendix B, along with the rationales for individual reference case selections.

Specific reference cases were chosen to permit quantitative comparisons to be made among the range of technology alternatives considered. Environmental factors estimated quantitatively include air pollution emissions, water requirements and solid waste. Factors such as health and safety risks, which are less readily quantified, are qualitatively described. For the purpose of this analysis, impacts are assumed to be proportional to production levels (e.g., impacts of a 200,000 BPD facility will be four times greater than 50,000 BPD).

As was discussed in Section 2, the fundamental "generator" of impacts is the basic programmatic decision to develop NOSR 1. In accordance with the CEQ regulations for implementing the National Environmental Policy Act (NEPA) only major, significant environmental effects are considered in this analysis. This level of detail is commensurate with the broad policy decisions to which this Environmental Impact Statement is addressed. Similarly, cumulative environmental effects of regional energy development are identified and discussed but are not analyzed in detail.

Once the decision to develop is made, the specific sites on NOSR 1 selected for mines, retorts, spent shale disposal, etc., and the specific engineering technologies and financial mechanisms selected to accomplish the development are not expected to significantly alter the types and levels of impacts discussed in this EIS. Certain refinements and new details to the analyses may be expected, however. To ensure that adequate information exists to support these site- and technology-specific determinations, a continuing environmental baseline monitoring program has been initiated for the Naval Oil Shale Reserves (NOSR 1) to develop long-term, site-specific environmental background information. This information will be used to perform more refined analyses of the environmental impacts of oil shale development on NOSR 1. This analysis will be incorporated into a site- and process-specific Environmental Impact Statement which will be prepared should it be decided to develop NOSR 1.

An analysis of the environmental consequences of alternatives, including development of NOSR 1, follows in Section 5.1. A comparative socioeconomic analysis is presented in Section 5.2. Unavoidable adverse environmental effects are discussed in Section 5.3; the relationship between short-term uses of the environment and the maintenance and enhancement of long-term productivity is discussed in Section 5.4; irreversible and irretrievable commitments of resources are identified in Section 5.5; and coordination with federal, regional, state, and local land use plans, policies, and controls is discussed in Section 5.6. Section 5.7 discusses other factors such as energy requirements and conservation potentials, historic and cultural resources, urban quality, and the design of the built environment.

5.1 ENVIRONMENTAL CONSEQUENCES

5.1.1 NOSR Oil Shale Development

The following sections discuss the impacts of oil shale development on the Naval Oil Shale Reserves I in Garfield County, Colorado. The reference case will use room-and-pillar mining and three surface retorting methods: vertical direct and indirect retorting for feedstock of 1/2 inch to 3 inches and a solid heat exchange method for fines retorting. The production levels being considered are 50,250 BPD and 201,000 BPD of shale oil, requiring a feed of 72,500 TPD and 290,000 TPD respectively of raw shale (31 gal/ton grade). Byproducts include low and high Btu gas, sulfur, and ammonia. The environmental impacts discussed would not vary significantly for the various NOSR development options (lease, quasi-utility, joint venture or GOCO) because the production facility is postulated to be the same for all development options.

Air Quality Impacts

Air quality impacts will result from mining and blasting, retorting, solids handling and disposal, and possibly liquid storage, and transportation. Mining and blasting will generate SO_2, CO, NO_x hydrocarbons and particulates. The retorting processes will generate the pollutants mentioned above as well as ammonia, hydrogen sulfide and polycyclic organic material (POM). POM includes polycyclic aromatic hydrocarbons, their sulfur and nitrogen analogues and oxidized derivatives. A number of trace metals and other elements occur in oil shale but for the most part they are not volatilized and remain in the spent shale. Mercury and arsenic are more volatile and are potentially significant non-criteria pollutants.[1] Arsenic is volatilized and must be removed from the shale oil or it will be released to the atmosphere when combusted.[2] Various known control technologies will be employed to control criteria and other pollutants.

Mining, blasting and primary crushing (performed in the mine) would produce approximately 9% of the particulates generated by the overall plant, while transportation, secondary crushing, and storage piles would contribute approximately 57%. The retort operations would contribute approximately 34% of the particulates generated. Mining and blasting (including diesel equipment) also will contribute approximately 44% of the SO_2, 39% of the NO_x, 58% of the CO, and close to 100% of the total hydrocarbons emitted by oil shale operations.[3]

Table 5-1 shows the total estimated controlled emissions of criteria pollutants for all the operations of a facility. These emission figures include emissions from mining, blasting, raw shale storage, transportation and preparation, and retorting.

Table 5-1.

Summary of Air Emissions for Mining and Retorting

	Emissions[4] (TPD)				
Production Level: Shale Oil (BPD)	SO_2	NO_x	THC	Part.	CO
50,250	1.1	11.1	0.8	2.9	2.0
201,000	4.4	44.4	3.2	11.6	8.0

These emissions may degrade the better-than-standard air quality over the NOSR 1 tract and could contribute to short term violations of federal air quality standards for particulates and hydrocarbons in the surrounding region. The impact of emissions from a 200,000 BPD facility may be more than four times as great as from a 50,000 BPD plant, depending upon the ability of the site to accomodate emissions, but this will not be known until site-specific modeling can be performed. NOSR 1 emissions could potentially affect visibility in the Flat Tops Wilderness Area to the northeast. The seriousness of this impact cannot be predicted at this point in the analysis. The cumulative effects of regional energy development could have a significant impact on air quality in the region. Areas in Mesa County to the south of Garfield County violate standards for particulates and are subject to inversions.

Wind erosion of spent shale piles will contribute particulate emissions to the ambient air. These are of concern because they may contain polycyclic organic material, a potential health hazard. The hazard potential of oil shale process chemicals is discussed under Health and Safety Impacts.

Water Resources Impacts

Demand

The production of 50,250 BPD of shale oil, using the reference technology, will require an input of 5.425 million GPD (5,461 AF/Y) of raw water for retorting facilities and spent shale disposal. A 201,000 BPD production level, using the same technology, will require 21,844 million GPD of raw water.

Indirect water requirements would result from increased human consumption due to population increases. The projected population growth for a 50,250 BPD NOSR project is estimated to be 7,500 (maximum) people. The 7,500 increase would be reached at the end of the sixth year after the project starts. For a 201,000 BPD operation, the total population increase would be 12,000 and would be reached at the end of the tenth year after the project started (assuming construction of the four 50,250 BPD plants would not start simultaneously).

Using 200 GPD per person domestic water consumption, the projected increase of domestic water demand is estimated to be 1.5 million GPD and 2.4 million GPD for the 50,250 BPD and 201,000 BPD operations, respectively. Total water consumption, including both process and domestic water requirements, would be 5.9 million GPD (5,964 AF/Y) and 24.1 million GPD (24,259 AF/Y) for the two respective cases, using the reference technology.

Water is relatively scarce in the Piceance Basin and largely allocated by water rights agreements. Diverting water to oil shale development should have a small effect on farming in comparison to other diversions, such as purchase of farm land for municipal growth. Nevertheless, farm production in Colorado could be reduced if rights to irrigation water were sold to oil shale developers. Such sales are not currently considered attractive to developers since only the actual seasonal water usage of any purchased rights can be utilized by the developer, regardless of the original water rights allocation. Even so, the purchase by industry of agriculture water rights is possible in the future when and if water shortages occur.

The reference case technology used in this discussion is not as water-intensive as some alternative technologies. If the most water-intensive technology being considered for NOSR 1 were chosen, the plant and domestic water requirements could be as high as 12,090 acre-feet/year for 50,000 BPD production and 48,350 acre-feet/year for 200,000 BPD production. It is not anticipated that NOSR 1 development will tax available water supplies in the area based on Colorado Department of Natural Resources estimates of water available for 1.3 million BPD of oil shale production. However, the impact of regional energy development on water supplies should be considered. Significant increases in water use can affect vegetative growth, aquatic and terrestrial animal populations, and could increase downstream salinity. High salinity is also a problem in the Colorado River Basin.

Availability

Project water requirements will probably be met by pumping water from the Colorado River, augmented by minor amounts of mine water. Groundwater is in short supply and is not considered a practical source.

The availability of water from the Colorado River for this project is dependent on water flow in the Colorado and the seniority of the project water rights. If a case of junior water rights dated 1980 is postulated, then there would be numerous occasions where water outages will occur. These outages, due to the inability to draw water from the Colorado without interfering with withdrawls by senior water rights owners, will occur every other year, on the average, and will be up to four months in duration. A four month outage is 7,281 AF of water for the 201,000 BPD production case. The estimates of water availability are based on historical data from Water Years 1954 through 1977.

There are two alternatives to solving the water outages for the project. The first involves the construction of a reservoir in the cinicity of the project site and filling it from the Colorado River during periods of high flow. The second is the purchase of water rights from an existing reservoir.

The construction of a reservoir to serve this project involves the construction of a dam to contain the water in one of the valleys on NOSR 1, NOSR 3 or on an adjacent property. This requires the movement of over eleven million cubic yards of material for an earth dam. The source of this material and its transportation to the site are problems of substantial magnitude. Solution of these problems will result in a reservoir of considerable expense. The water required to fill the reservoirs is available and could be pumped from the Colorado during high flow periods even for junior water rights.

The second alternative involves purchasing the water from an existing reservoir on the Colorado River system upstream from the project site. Then, when a water outage occurred the water could be released from that reservoir and flow down the Colorado. An amount equal to that released (but adjusted for losses) would then be pumped to the project site from the same diversion point on the Colorado as is normally used.

Two federal reservoirs exist with sufficient capacity to supply the emergency needs of the project, the Ruedi and Green Mountain Reservoirs. They are administered by Water and Power Resources Service of the Department of Interior. The cost from this source appears to be considerably less than the cost of construction of a reservoir for sole use by the project. Furthermore the large federal reservoir is managed by trained personnel in accordance with applicable environmental and other regulations. An emergency water supply option has not been determined but the federal reservoir would be the option of choice.[6]

Water Quality

Oil shale production will produce waste waters from retorting and upgrading operations, air and water cleanup units, cooling units and boiler blowdown, and sanitary waste waters. The reference case is assumed to have a zero discharge design in which waste waters are treated and either recycled or used for wetting of retorted shale so that it may be compacted. Therefore, there should be no discharge of waste waters. However, surface or groundwater contamination could occur as the result of leaching from spent shale disposal piles, unintentional releases from impoundments, spills from process equipment or storage tanks, and in transportation.

Process waters may contain a number of hazardous materials which could damage aquatic and land species if accidentally released. These include ammonia, organic acids, suspended organic compounds (phenolics, amines, hydrocarbons, mercaptans), and smaller quantities of trace elements.[3] The impact of a release of these substances on the surrounding environment would depend on the size of the release and the specific source of the waste waters.

A significant potential source of water contamination is the leachate from spent shale piles. Spent shale will be disposed of in canyons or natural depressions of the landscape and measures taken to impound leached waters and revegetate the spent shale surface. The failure of dams and impoundments to contain leachates could result in their release to surface or ground waters. Analyses of leachates from spent shale indicate the presence of phenols, trace elements (e.g., arsenic, boron, lead), and high concentrations of dissolved solids.[7]

Construction and transportation will increase the sediment load to nearby surface waters. Methods are available to mitigate, but not completely prevent, sedimentation.

Solid Waste Impacts

The 50,250 BPD production level is expected to generate 58,875 tons of spent shale and 1,733 tons of other solid wastes per day. At 200,000 BPD production rate, solid waste generated will be four times as much. The solid wastes other than retorted shale include water treatment sludges, spent catalysts and shale oil coke. Disposal of a total of 60,608 TPD of solid waste will require large areas of NOSR 1 land, primarily in valleys or canyons. Spent shale disposal sites will need to be designed to provide stability, leachate control, and revegetation potential. Standard mine engineering parameters will be used to determine the design and slope necessary to assure the stability of the pile. These parameters must be determined on a process-specific level, and include such things as the sheer strength of the spent shale, water content, and degree of compaction. Leachate control is needed to prevent the contamination of surface and groundwater with trace elements and organic materials. Potentially leachable trace elements include Cl, F, K, Ca, Si, Na. Organics present may include phenolic compounds and organic nitrogen compounds. Revegetation will require site preparation (preleaching and perhaps soil replacement), seeding, fertilization, and irrigation.

Land Use

Underground mining creates the possibility of surface disturbance due to subsidence. However, the room-and-pillar method of mining is designed to prevent this occurrence. Over the life of the project, retorting facilities and raw shale storage will require the use of 300 acres of land for the 50,250 BPD production level and 1,200 acres for the production of 201,000 BPD. A reserve water supply will be stored in a reservoir constructed onsite, precluding mining beneath the storage area. The affected area will be small, however. The major land use will be for the disposal of spent shale. The 50,250 BPD production level will generate approximately 20 million tons of solid wastes annually. A 1,070-acre disposal site at the headwaters of Trappers Creek is under consideration. This site would be filled to an average depth of 185 feet. The affected land would undergo significant changes in contour and drainage, as well as vegetation. Stream diversion may be necessary to mitigate the effects of leachates coming from the spent shale pile. The overburden of the shale resource is sufficiently thick to allow mining of the raw shale beneath the disposal area.

Land use also will be affected by the pipeline used to transport the product oil. The pipeline route has not been determined for NOSR 1. Under consideration is a route which would take the product north to Casper, Wyoming. The corridor for this route would be 275 miles long and 50 feet wide. Existing pipeline corridors would be used to the extent possible. Utility corridors for power lines, water pipes, and so forth, will be consolidated to the extent possible. Along with product pipeline corridors and site access routes they represent a significant offsite land use impact.

Health and Safety Impacts

A number of potentially hazardous materials are produced in the solid, liquid and gas streams of shale oil processes. Workers may be exposed to these substances by contact with the process steams or with fugitive emissions. These substances also could be released into the ambient air through fugitive emissions and control off-gases. This would create a potential for public health effects through low-level, long-term exposure. Polycyclic organic material residing on spent shale particles could result in exposure by inhalation of respirable particulates. The presence of suspected carcinogens in shale oil is the chief health concern. Benzo(a) Pyrene, which is frequently used as a gross indicator of carcinogenicity, is present in raw shale at a concentration of 30,000 to 40,000 ppb, and in crude (upgraded) shale oil at 3,130 ppb. By comparison, the concentration of BaP in other petrochemical substances ranges from 1,320 ppb in Libyan crude oil to 10,000-100,000 ppb in asphalt.[2] However, some controversy exists over the use of BaP as an indicator of carcinogenicity. The effects of other constituents of shale oil and associated products, as well as the synergistic effects of various shale oil constituents, are not certain.

Other occupational hazards present in shale oil production include the potential for accidents associated with underground and heavy equipment uses, equipment failure, high temperature operations, and fire and explosion hazards associated with hydrocarbon industries. The hazards generally associated with coal mining (such as cave-ins and dust inhalation) are less likely to occur in oil shale mining due to the stronger mechanical properties of the shale. Data to quantify the frequency and severity of accident occurrences are not yet available for oil shale mining or processing.

Ecosystem

Noise and surface disturbance would displace most terrestrial species in the immediate area of development. Plant and animal habitats would be destroyed by onsite development (mine, retort facilities, spent shale disposal, etc.) and by the clearing of utility and pipeline corridors. In addition, the presence of the plant and product pipeline will present a potential for plant and animal impacts due to accidental oil spills. Proper pipeline design can mitigate impacts on migratory species. Onsite development should be possible without the destruction of the only federal endangered species on the NOSR 1, the grass Festuca dasyclada. Should NOSR 1 be developed, a formal consultation with the U.S. Fish and Wildlife Service will be initiated, as provided by the Endangered Species Act. Development in those areas which are heavily utilized by summering mule deer and elk would result in relocation of these species to other summer ranges, both on and off the tract. At present these ranges are less limited than the winter ranges of these species, which occur off the NOSR property.

There is a potential that NOSR 1 development will result in the destruction of a portion of the habitat utilized by the Colorado cutthroat trout (listed as threatened by the state of Colorado). Possible mitigative actions include location of facilities upstream from waterfalls which already prevent the fishes migration; control of leachates, and other types of water pollution control. This species is not limited to a specific site on NOSR, but occurs in most of the larger creeks on the west side of the tract, and in various locations in the upper Colorado River Basin.

The disposal of spent shale will destroy floral and faunal habitats of the affected area in the short term. Reclamation efforts, if successful, would establish some plant species over the spent shale disposal area. However, due to the absence of a mature plant population, the reestablished community would not achieve the original mix for a long period of time. Furthermore, recontouring of the topography will tend to level out steep slopes, altering the exposure to sun, wind, and water. As a result, the original plant communities will be replaced by species better adapted to the altered habitat. Animal populations may be similarly altered.

Removal of large quantities of water, as well as diversion of streams due to spent shale disposal, may result in decreases in the fish population. Air and water pollution also can affect plant and animal distribution in the affected area.

Major Uncertainties

The effectiveness of measures to control spent shale leachate to protect surface and underground water over long periods is uncertain. Similarly, the success of reclamation and revegetation efforts is uncertain over the long term. Studies have been and are being conducted to develop successful reclamation procedures over spent shale piles.

The effect of air emissions on regional air quality, and specifically on the Flat Tops Wilderness Area, is also uncertain due to inadequacies in dispersion modeling over complex terrain.

Ongoing toxicological studies will help assess the hazard potential of various chemicals present in oil shale processes.

Long-Term Impacts

The most obvious long-term impact of shale oil development will be the permanent changes in topography effected by large spent shale disposal areas. The air quality impacts may affect animal and plant populations in the long term. In particular, long-term exposure to potential carcinogenic substances could impact the health of human and animal populations in the region.

Removal of large quantities of water from surface streams could have long-term impacts on water table depth and aquifer recharge. The surface disposal of spent shale and its compaction to reduce permeability will remove these areas from the aquifer recharge system. Over the life of the facilities (either 50,250 or 201,000 BPD), up to four percent of available surface area will be sealed and removed from aquifer recharge. The trapped water would directly aid the revegetation of the spent shale area and would be returned to the atmosphere by evaporation.

Cumulative Environmental Impacts

The potential exists for cumulative environmental impacts from the development on NOSR due to the planned development on other oil shale tracts in the region as well as those adjacent to the NOSR. The latter includes the Colony, Union, and Mobil projects. The first two are under construction while Mobil is conducting environmental studies for permit applications. Cumulative environmental impacts which could occur include air and water quality degradation, changes in vegetation patterns, and changes in wildlife habitat and migratory patterns. The air quality issue has received much attention due to several reasons: air quality levels in the oil shale region are good to excellent in comparison with EPA air quality standards; the existence of Flat Tops, a Federal Class I wilderness area, northeast of the Piceance Basin; and the difficulty in air pollutant dispersion modeling due to the complex terrain features characteristic of northwestern Colorado.

Cumulative air quality impacts have been addressed in recent studies, but the development scenarios used have changed since the studies were completed [36,37]. They do, however, provide an insight into potential impacts as well as the problems in assessing the impacts. In the first study, two phases were analyzed. The first phase addressed the impacts of oil shale development up to 880,000 bbls/day by 1995 for sulfur dioxide, suspended particulates, nitrogen dioxide and ozone. Visibility effects on Class I areas were also examined. In the second phase, a study was made of the generation of ozone at a level of development up to 8 million bbls/day by 2010. The phase I analysis indicated that levels of suspended particulates and sulfur dioxide were within the PSD Class II limits at all distances beyond local impacts, and are within Class I limits at Flat Tops Wilderness and Dinosaur National Monument. At short range, the TSP and SO_2 Class II limits could be exceeded near an oil shale plant. The phase II study indicated that strong visibility impacts could occur.

In the second study, an air quality impact analysis was conducted for energy development in the Four Corners region. Three scenarios of energy development for several synfuel technologies were used, including 13 oil shale projects in Colorado. Air Quality analyses were done for sulfur dioxide, fine particulates and visibility. Under the high scenario, oil shale development exceeded 900,000 bbls/day without any adverse impacts on PSD increments or visibility.

Cumulative water quality impacts could also occur from NOSR development, affecting surface water primarily. During construction operations, access roads to the site will be heavily travelled causing come soil erosion which may run off into creeks draining into adjacent oil shale tracts. Mitigating measures include construction of catchment basins near the boundaries of the NOSR property. Cumulative impacts on groundwater would be less than for surface waters since the groundwater system underlying NOSR 1 and 3 for about the first 2,000 feet is nearly an island unto itself, having very little interaction with the rest of the Piceance Basin.

There are several reasons why cumulative impacts cannot be accurately quantified at this time:

1. Development schedules for several projects are not well defined.
2. The retorting methods to be used have not been seleted for all projects.
3. Methodologies do not exist for accurately quantifying cumulative impacts.

Recognizing these limitations, the potential for cumulative impacts does exist since there could be significant development in the oil shale region by the end of this decade, much of which would be concentrated in the vicinity of the NOSR and the remainder in the Piceance Basin. At such time as the decision to develop NOSR 1 is made, cumulative air quality analysis will be performed, and reflected in appropriate NEPA documentation. A cumulative socioeconomic impact analysis for a three county region in Colorado affected by hypothetical oil shale development was performed, and is discussed in Section 5.2.3.

5.1.2 Increased Conservation

A reference case for energy conservation in the transportation sector is projected to illustrate the potential reduction in pollutant emissions which could accompany nationwide reductions in gasoline consumption of 50,000 and 200,000 BPD. The gasoline savings are assumed to result from a decrease in vehicle weight only.

Air Quality

Increased conservation in the transportation sector could result in decreased air pollutant emissions and a resultant improvement in ambient air quality. Assuming that total passenger car vehicle miles traveled (VMT) in 1990 are 2.7 billion miles per day nationally[8] and 12 million miles per day in the Denver metropolitan area[8,9] 100 million gallons (2.4 million barrels) of gasoline would be consumed in the U.S. and 450,000 gallons (11,000 barrels) would be consumed in the Denver area. Total exhaust emissions resulting from combustion of this fuel are projected using EPA emission factors and are presented in Table 5-2.

Table 5-2. Total Daily Exhaust Emissions in 1990

	CO (TPD)	HC (TPD)	NO_x (TPD)	SO_2 (TPD)	Particulates (TPD)
U.S.	12,000	1,700	3,500	370	110
Denver Metropolitan Area	54	7.4	16	1.7	0.50

Conservation of 50,000 or 200,000 BPD of gasoline nationwide would constitute reductions of 2.1 percent and 8.3 percent respectively. If emission reductions correlate directly with a decrease in fuel combustion, then emissions would be reduced by the same percentages. Maximum emission reductions for these reference cases are presented in Table 5-3.

Such reductions in exhaust emissions will improve air quality in the Denver metropolitan area. This is significant because the Denver Air Quality Control Region violates the National Ambient Air Quality Standards for carbon monoxide (CO), total suspended particulates (TSP), nitrogen dioxide, and photochemical oxidants.[10] Oxidants are produced by the reaction of atmospheric hydrocarbons with NO_x and sunlight and can be represented by measurements of hydrocarbons. Denver air quality was considered "unhealthful" an average of 157 days per year in the period from 1975 through 1977, using the Pollutant Standard Index developed by EPA for public reporting of daily air quality. Of the 157 days, the air quality was "very unhealthful" an average of 30 days per year. In 1977, high levels of carbon monoxide (CO) were primarily responsible for the poor air

Table 5-3.

Exhaust Emissions Reductions From Conservation Reference Cases

	CO TPD	HC TPD	NO_x TPD	SO_2 TPD	Particulates TPD
National Reductions					
50,000 BPD case	250	33	73	7.7	2.3
200,000 BPD case	1000	140	290	31	9.3
Denver Reductions					
50,000 BPD case	1.1	0.16	0.33	0.037	0.010
200,000 BPD case	4.3	0.63	1.3	0.14	0.040

quality 127 days out of a total of 143 days.[11] Particulates and photochemical oxidants also were responsible for unhealthful conditions. The CO and photochemical oxidants are generated primarily by mobile sources such as passenger automobiles. In 1976, light-duty, gasoline-powered vehicles were responsible for 55 percent of carbon monoxide emissons in the Denver area.[12] If CO emissions were reduced by 2.5 percent in the 200,000 BPD case and passenger vehicles accounted for 55 percent of carbon monoxide emissions, these overall CO emissions could be reduced by 1.4 percent. This reduction would help to alleviate Denver air pollution problems since CO is the most important factor in Denver air quality violations.

The values for the emission reductions should be considered as maximum values because emission standards are written in grams per mile and fuel efficiency standards are written in miles per gallon. A manufacturer can be expected to optimize vehicle design to meet both standards. There is no incentive to use costly emissions control equipment if emission standards can be met by distributing the emissions from a gallon of fuel over a greater number of miles by increasing fuel efficiency. Many small cars do not burn fuel cleanly and yet meet emission standards because of their high fuel efficiency. For this reason actual reductions in emissions would probably not correlate directly with an increase in fuel efficiency and would be less than the values presented above.

Emissions were projected from emission factors developed by EPA. These factors incorporate such elements as emission standards, average driving conditions, altitude, and emission control effectiveness over time. Emission factors for the 1990 fleet are projected by model year in Table 5-4. Values for average model year fuel efficiency and fraction of travel also are presented in the table. The fraction of annual travel is derived from the average number of miles traveled by cars of a particular age and the percentage of the fleet constituted by cars of that model year. The fraction of travel is used to weight the emission factors and total fuel consumption to estimate the relative emission contribution and total fuel consumption of cars from a given model year. Total fuel consumption is calculated from total vehicle miles traveled (VMT), average fuel efficiency, and the fraction of travel for each model year. The values assumed for VMT are 2.7 billion miles per day for the U.S. as a whole, and 12 million miles per day for the Denver metropolitan area.

Emissions from sources other than fuel combustion can be expected to remain basically unchanged by the conservation alternative. These sources include hydrocarbons from crankcase emissions and particulates released from tire wear.

Water Resources Impacts

Water quality may improve slightly due to lower levels of particulates in the atmosphere which ultimately could be transported and deposited into bodies of water. The reference case would not generate any negative effects on water quality and probably would not significantly alter existing water consumption by the auto industry.

Solid Waste

The reference case would probably not change current production of solid wastes by the auto industry appreciably or generate negative environmental impacts.

Land Use

The reference case as defined will probably not generate any appreciable changes in land use.

Table 5-4. Passenger Automobile Fleet Emission and Fuel Efficiency Factors for 1990

	Exhaust Emission Factors[a]						
Model Year	CO g/mi	HC g/mi	NO_x g/mi	SO_2 g/mi	Part. g/mi	Average Fuel Efficiency[b] mi/gal	Fraction of Travel[a]
1977	18.0	3.0	2.60	0.13	0.05	15.6	0.026
1978	18.0	3.0	2.60	0.13	0.05	18.0	0.013
1979	18.0	3.0	2.60	0.13	0.05	19.0	0.013
1980	8.7	0.81	2.60	0.13	0.05	20.0	0.019
1981	5.3	0.76	1.36	0.13	0.05	22.0	0.032
1982	5.0	0.70	1.32	0.13	0.05	24.0	0.047
1983	4.8	0.65	1.28	0.13	0.05	26.0	0.063
1984	4.5	0.59	1.24	0.13	0.05	27.0	0.079
1985	4.2	0.54	1.20	0.13	0.05	27.5	0.094
1986	3.9	0.49	1.16	0.13	0.05	27.5	0.108
1987	3.6	0.43	1.12	0.13	0.05	27.5	0.121
1988	3.4	0.38	1.08	0.13	0.05	27.5	0.130
1989	3.1	0.32	1.04	0.13	0.05	27.5	0.143
1990	2.8	0.27	1.00	0.13	0.05	27.5	0.112

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[a] Reference 13 (emission factors are modified to incorporate 1977 CAA amendments)

[b] Reference 14 (value for 1977 model year is actual average; values for other model years are legal requirements)

Health and Safety

Improvements in air quality which could result from the reference cases would have a positive health effect. As noted above, Denver air quality is unhealthful a significant portion of the year. Such poor air quality can aggravate symptoms of heart and lung diseases and can decrease exercise tolerance. An improvement in air quality will reduce such effects.

Ecosystem Impacts

A reduction in exhaust emissions will reduce the negative effects of air pollutants on vegetation and may increase productivity. Minor water quality improvements possibly could increase the productivity of aquatic communities.

Long-Term/Cumulative Impacts

Increased conservation should result in improved air quality. As less fuel is burned, fewer conventional pollutants should be released into the atmosphere. The degree to which emissions reductions will be proportional to reductions in fuel consumption is uncertain because of the way in which emission and fuel efficiency standards are written.

Reduced fuel combustion will result in a decrease in the release of carbon dioxide (CO_2) into the atmosphere. This may be the most significant long-term effect of increased conservation. Scientists are concerned that increased atmospheric CO_2 levels may result in significant long-term climatic changes.[15] Although there is some question as to whether the reference cases would result in a reduction of conventional pollutant exhaust emissions, a reduction in fuel combustion will result in a corresponding reduction in the amount of CO_2 released to the atmosphere, due to the stoichiometric relationship of fuel carbon content to CO_2 produced.

5.1.3 Oil Shale Development on Other Lands: Impacts

This section discusses the environmental impacts of oil shale development on lands other than NOSR 1. The reference case selected is development of the Dow West (Colony) property using the TOSCO II retorting process. The process utilizes hot ceramic balls to retort preheated oil shale by direct solid to solid heat exchange.

The main products are hydrotreated oil and LPG. Byproducts include sulfur, ammonia, coke, and high Btu gas. The reference case production level is 47,900 BPD (44,400 BPD of shale oil and 3,500 BPD of LPG). This production level would require an input of crushed shale at the rate of 66,000 TPD.

Air Quality Impacts

Sources of air emissions include mining, blasting, solids handling, wind erosion, retorting and upgrading units, and liquid storage. Mining would produce particulates, hydrocarbons, NO_x, and CO. Wind erosion of raw shale storage piles would generate particulate matter but is expected to be minimized through wetting procedures.[16] However, the amount of particulates generated in this way would tend to be greater for this reference case than for the NOSR 1 alternative due to the smaller sized feedstock required for the TOSCO II process (half-inch as opposed to 1/2 to 3 inches). Particulates generated from spent shale disposal areas are of concern because they may contain polycyclic organic material. The hazard potential of oil shale process chemicals is discussed under health and safety impacts.

Retorts will emit the criteria pollutants SO_2, NO_x, CO, hydrocarbons, and particulate matter. In addition, they may emit quantities of ammonia, hydrogen sulfide and polycyclic organic material. Table 5-5 summarizes maximum plantwide emissions of criteria pollutants for the two reference case production levels. The data include emissions from the primary crusher in the mine, the portal transfer, and fine ore storage, but do not include emissions from the mines vent or spent shale disposal area. An additional 0.2 TPD of fugitive dust (particulates) may be generated from the mine vent, unpaved roads, the crusher dump, coarse ore storage, delayed coker dump and processed shale disposal.

These emissions may degrade the better-than-standard air quality over the Colony tract and could contribute to short-term violations of federal air quality standards for particulates and hydrocarbons in the surrounding region. They could potentially affect visibility in the Flat Tops Wilderness Area to the northeast. Areas in Mesa County to the south of Garfield County violate standards for particulates and are subject to inversions.

Table 5-5. Emissions of Criteria Pollutants

Shale Oil	Emissions after controls[17] (TPD)				
Production Level (BPD)	SO_2	NO_x	HC	PM	CO
47,900	3.8	20.9	3.6	3.1	0.8
200,000	15.2	83.6	14.4	12.4	3.2

Water Resource Impacts

The production of 47,900 BPD of shale oil and LPG using the reference design would require a raw water input to the plant of 8.08 million GPD (24.8 acre-feet). Indirect water requirements would result from increased human consumption due to population growth. The project-induced population growth for a 47,900 plant is estimated to be 8,000 persons. The impact on domestic water supplies can be estimated by using 160-200 GPD per person water consumption. The maximum projected increase in domestic water demands is approximately 1.6 million GPD (4.9 acre-feet). The aggregate plant and domestic water requirements would be 9.7 million GPD (29.7). These raw water requirements are in addition to any process-produced or mine dewatering sources of usable water.

The withdrawal of large quantities of water from the area affects surface water flow and the water table. Sufficient water rights have already been obtained. However, cumulative water use due to regional energy development potentially could affect vegetative growth, aquatic and terrestrial animal populations, and would tend to increase downstream salinity. High salinity concentrations are a serious problem in the Colorado River Basin.

Water pollution could occur as the result of waste water release, leaching from storage/disposal areas, or spills of products and process chemicals. Oil shale production would produce waste waters from retorting and upgrading operations, air and water cleanup units, cooling units and boiler blowdown, and salinity waste treatment. Waste water would be produced at the rate of 594,000 GPD. The waste water would be recycled to meet some process water requirements and used for moisturizing the spent shale. However, surface or groundwater contamination could occur as the result of leaching from disposal piles, unintentional releases from water containment areas, and spills from process equipment and storage tanks.

Process waters may contain a number of hazardous materials which could damage aquatic and land species if accidentally released. These include ammonia, organic acids, suspended organic compounds (phenolics, amines, organic acids, hydrocarbons, mercaptans), and smaller quantities of trace elements. The impact of a release of these substances on the surrounding environment would depend on the size of the release and the specific source of the waste waters.

A significant potential source of water contamination is the spent shale disposal area in Davis Gulch. Davis Gulch drains into Parachute Creek, a tributary of the Colorado River. A dam at the lower end of the disposal area would contain runoff water from the disposal area in a lined holding area until it is reused. This water may contain hazardous substances such as phenols and arsenic.[13] It would have a total dissolved solids concentration of approximately 40,000 ppm, 99% of which would be comprised of inorganic salts. The remaining 1% (estimated) would be made up of organic material from hydrocarbon residues. Water quality damage could occur as the result of lining failure, dam failure, or percolation from the disposal pile.

Solid Waste Impacts

The 47,900 BPD case will generate an average of 55,397 TPD of solid waste. Spent shale accounts for 53,200 TPD. The remaining 2,197 TPD is comprised of spent catalysts, shale dust, shale coke, and water treatment sludges. 872 acres of land will be required for solid waste disposal over the 20-year life of the oil shale project. In addition, another 72 acres will be required for diversion structures to control runnoff from the shale embankment. Leachates from the disposal area will be collected and reused so that water resources are not contaminated by substances leached from the spent shale and other wastes. The area will be graded to resemble existing topography and will be revegetated.

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Land Use

Development of a 47,900 BPD oil shale complex on the Dow West property will require 175 acres for the plant complex and ore storage, 42 acres for the mine bench and flood control dam, 350 acres for roads and conveyor routes, and 872 acres for spent shale disposal.[16] Additional acreage would be required for some offsite facilities and pipeline and powerline rights-of-way. Colony has cancelled plans to construct a 194-mile-long pipeline to Lisbon Valley, Utah, but has not yet announced an alternate plan.

The topography of the site will be altered to accomodate the plant and by spent shale disposal. Dams and diversion structures, as well as topographical changes, will alter drainage patterns. Diversion structures are necessary to control potential adverse effects on water quality from plant runoff and leachates from spent shale disposal. Topography also may be altered by subsidence of the mine. The room and-pillar method of mining is designed to prevent this occurrence.

Health and Safety Impacts

A number of potentially hazardous materials are produced in the solid, liquid and gas streams of shale oil processes. Workers may be exposed to these substances by contact with the process streams or with fugitive emissions. Polycyclic organic material residing on spent shale particles could result in worker exposure by inhalation of respirable particulates. If released to the ambient air, these substances could create a potential for public health effects through low-level chronic exposure. The presence of suspected carcinogens in shale oil is the chief health concern. Benzo(a)Pyrene, which is frequently used as a gross indicator of carcinogenicity, is present in raw shale oil at a concentration of 30,000 to 40,000 ppb, and in crude (upgraded) shale oil at 3,130 ppb. By comparison, the concentration of BaP in other petrochemical substances ranges from 1,320 ppb in Libyan crude oil to 10,000-100,000 ppb in asphalt.[2] Some controversy exists over the use of BaP as an indicator of carcinogenicity, however, because it has not been shown to produce cancer in humans. In addition, it does not take into account synergistic effects of multiple carcinogens, and effects of co-carcinogens which may enhance the effects of carcinogens. Additional testing of shale oil and refined products is in progress.

Other occupational hazards present in shale oil production include the potential for accidents associated with underground and heavy equipment uses, equipment failure, high temperature operations, and fire and explosion hazards associated with hydrocarbon industries.

Ecosystem Impacts

Oil shale development on the Dow West site would affect both vegetation and wildlife. Effects on vegetation would result primarily from clearing. Wildlife would be affected by increased human activity and disturbance, habitat alteration, decreased water availability, and potentially by degraded water quality.

Vegetation will be removed around the retort/upgrading complex and along pipeline and powerline corridors. Spills, uncontrolled fires, and off-road vehicle use could also affect vegetation. Adverse effects from air pollution are expected to be negligible but could become significant if additional oil shale development occurs in the area. Yellow columbine (endangered) and sullivantia (threatened) may be eliminated from two sites due to decreased water availability; however, both species also occur in other areas on the property which should not be affected by development. Disposal of spent shale will destroy vegetation in the disposal area. The disposal site will be reclaimed by reintroducing native plant species.

Destruction of habitat and increased human activity may cause mule deer from the Parachute Creek valley to winter in the Roan Creek area. This would result in increased competition for food and may reduce the herd size through increased mortality. Secretive animals such as mountain lions and black bears will avoid the property. Construction will affect fish populations in Parachute Creek due to siltation. Proper controls during the construction period can mitigate this impact. Following construction, natural stream action will remove excess silt over time. Restocking of the stream should replenish affected fish populations.

If spills of shale oil or toxic materials occurred, all aquatic life in Parachute Creek could be killed, and aquatic communities in the Colorado River could be adversely affected. Other animals also may be affected by increased human presence and activities.[16]

Major Uncertainties

The success of reclamation and revegetation of spent shale is uncertain over the long term. Studies have been and are being conducted to develop successful reclamation procedures. The effectiveness of controls for spent shale leachates over long periods of time also is uncertain. In addition, further toxicological testing is needed to assess the hazard potential of the various chemicals present in oil shale processes.

Long-Term Impacts

The most obvious long-term impact of shale oil development will be the permanent changes in contour and topography affected by large spent shale disposal areas. Chronic health effects such as potential carcinogenicity are also a significant concern. Wildlife will be affected by the removal of their habitats and by increased human activity. Mining will affect the local hydrology of the area, as will increased water use over a long period of time. Reduced streamflow in the immediate vicinity of the plant due to increased water usage will affect plant and animal occurrence and distribution. Water use will also preclude use for other purposes. This effect would be reversible unless groundwater resources were tapped and were used more rapidly than they were replenished. Primary water supply will be the Colorado River. However, use of groundwater resources is planned during construction and, if found reliable, will be used for plant operation.

5.1.4 Enhanced Oil Recovery

Enhanced oil recovery refers to various methods of producing oil from reservoirs which no longer respond to conventional recovery methods (pumping and water flooding). Tertiary recovery methods presently being studied include chemical flooding (including micellar polymer), CO_2 flooding, and thermal methods. Thermal methods have been used effectively in the recovery of heavy, viscous oils, such as those produced in Kern County, California. Steam flooding, the thermal method selected for the reference case, utilizes separate injection and production wells. Injecting steam enhances the recovery of heavy oils by expanding the oil and reducing its viscosity, by pushing the oil toward the recovery well, and by steam distillation.

The following section discusses the environmental impacts associated with the production of 50,000 BPD and 200,000 BPD of crude oil by steam flooding in Kern County, California. While the 200,000 BPD case is not feasible in Kern County alone due to resource limitations and air quality impacts, it is achievable nationwide, and is included for comparison with other alternatives. The 50,000 BPD and 200,000 BPD production levels would require the burning of 20,000 and 80,000 BPD respectively of crude oil to produce steam for injection.[18] (The 50,000 BPD and 200,000 BPD figures are the net crude oil produced.) While alternative fuels could be used for steam generation, they would significantly increase the cost of production. Production would require an estimated 1,100 production wells and 1,400 injection wells for the 50,000 BPD case. 4,400 production wells and 5,600 injection wells would be required for the 200,000 BPD case.

Air Quality Impacts

Air pollution emissions from oil-fired boilers constitute the most severe environmental impact of the steam flooding process. The crude oil produced in Kern County is relatively high in sulfur (approximately 1.5%). Its combustion would result in the emission of large amounts of SO_2, as well as NO_2, particulates, hydrocarbons, and carbon monoxide. The estimated uncontrolled emissions of these pollutants are shown in Table 5-6 for the 50,000 BPD and 200,000 BPD reference cases. If controls are assumed for SO_2, NO_2, and particulates with efficiencies of 95%, 60%, and 95% respectively, the controlled emissions for the 50,000 and 200,000 BPD cases would be 5.0 and 19.8 TPD of SO_2, 10 and 40 TPD of NO_2, and 0.35 and 1.4 TPD of particulates.

Table 5-6. Uncontrolled Emissions for EOR

		Emissions[19] (TPD)				
Net Oil Production Production (BPD)	Oil Burned for Generation (BPD)	SO_2	NO_2	Part.	HC	CO
50,000	20,000	99	25	7	1	1
200,000	80,000	396	100	28	4	4

Parts of Kern County are non-attainment areas for SO_2, particulates, carbon monoxide and photochemical oxidants (formed by the reaction of NO_x with hydrocarbons in the presence of light). The emissions from steam generation would exacerbate the already poor air quality in Kern County. Pollution control devices such as FGD scrubbers would mitigate the impact, but may not be able to provide sufficient emission reduction at an acceptable cost. The air quality impacts of 200,000 BPD production may be much more severe than for 50,000 BPD and may not be possible in Kern County due to air quality restrictions, as well as resource limitations.

Other potential emissions from steam flooding include trace elements in the burned oil, and hydrocarbons from the production wells and storage facilities. Trace elements commonly found in California crude oil include manganese, nickel, vanadium and tin[18], none of which are currently regulated as hazardous air pollutants. Hydrocarbon emissions from production wells and storage tanks can be controlled with vapor recovery systems, and would be significant only in the event of an oil spill or other accident.

Water Resource Impacts

Steam flooding is a water-intensive process. The production of 50,000 BPD (net) of oil would require 18.8 million GPD (18,941 AF/Y) of water for steam generation. 200,000 BPD production would require 75.3 million GPD (75,764 AF/Y) of water.[20]

Approximately one-third more water is produced with the oil than is injected as steam in the Kern River field. Producers attempt to maintain the ratio of water injection to water production at 1.0. If this water is of sufficient quality it can be treated and used for steam generation.

Groundwater is quite variable in Kern County, and generally of poor quality. A steam injection project at the Kern River field near Bakersfield reuses produced water for steam generation after extensive treatment. However, water produced at the Midway-Sunset field is extremely high in dissolved solids and hardness and cannot be economically treated for reinjection use as boiler feedstock.[20] Brines produced from the Midway-Sunset field are disposed of in evaporation ponds to avoid contamination of surface and ground waters.[19] Steamflood operations requiring water from outside sources could severely tax available water resources in the surrounding area. Prior commitments of available water supplies could impede the development of enhanced recovery projects in parts of Kern County.

Contamination of groundwater sources through leaks in well casings generally is a concern in pressurized injection operations and oil production in general. However, due to the essential lack of potable groundwater in Kern County, the potential for water quality damage is greatly reduced.

Spills of oil or produced brine could occur as the result of accidents at the wellhead, storage facilities, or along the transportations route. The contamination of surface waters due to spills is a concern only in limited sections of the county, due to the scarcity of perennial streams. In areas where useable water is present, spillage of large volumes of oil or brine could have serious impacts on aquatic and terrestrial species, causing stunted growth or death.

Leachates from scrubber sludge also could contribute to water pollution. The disturbance of the surface during construction could impact streams by increasing erosion and siltation. These disturbances would be of concern only in parts of the county where surface water is present. Most existing streams are already high in dissolved solids due to natural sources.

Solid Waste Impacts

The primary solid waste associated with steamflooding is sludge, produced by pollution control units and onsite processing of produced oil. Since oil produced by steam flooding does not require upgrading before transportation, the most significant source of sludge is the pollution control equipment. Control of sulfur emissions is of particular importance. Assuming an average sulfur content of 1.5% in the oil burned for steam generation and 90% surfur removal efficiency, the 50,000 BPD case would generate approximately 367 TPD of wet sludge from a typical limestone FGD scrubber. The 200,000 BPD case would generate 1,468 TPD from this source.

Other solid wastes generated by steamflooding operations include drilling muds and fines, and wastes from site preparation. Drilling muds and scrubber sludge may contain toxic substances which could potentially degrade water quality. However, solid wastes generated by this alternative are generally less hazardous and of much smaller volume than those produced by the oil shale alternative.

Land Use Impacts

The production of 50,000 BPD of crude oil would require approximately 1,100 production wells and 1,400 injection wells. A surface area of approximately 4,000-5,000 acres would be utilized (16,000-20,000 acres would be utilized for the production of 200,000 BPD of oil). Grazing is the land use most likely to be impacted, although much of the affected area could be used simultaneously for grazing if hazardous areas (i.e., machinery and landfills) were fenced off. Grading and recontouring could degrade land quality by accelerating erosion and increasing the potential for mudslides. Reclamation procedures and proper contouring would mitigate these effects. Subsidence may result from oil and water removal. This is less likely than in conventional recovery since a large percentage of the removed fluid volume is replaced. Finally, fluid injection may increase the risk of seismic events.

Health and Safety Impacts

Workers in steamflooding operations are exposed to the hazards normally associated with oil recovery, such as heavy equipment accidents, explosions, blowouts, fire and contact with the many organic substances found in heavy crude oil. Additional hazards result from the use of pressurized steam, which can result in the release of extremely hot gas in the event of equipment failure. Data to quantify the frequency and severity of accident occurrences are not available for steam injection recovery.

Ecosystem Impacts

Ecosystem impacts associated with enhanced oil recovery include the disturbance of habitats and subsequent changes in population dynamics due to degradation of air, water, and land. Although similar impacts are associated with oil shale development, the impact of enhanced oil recovery on the whole is less severe since it generally occurs in areas which have already been developed for oil recovery. EOR may affect the endangered San Joaquin kit fox and the blunt-nosed leopard lizard by changes in habitats. The endangered California condor, whose feeding range extends into the oil producing region, would not be significantly affected by steamflooding operations, since its nesting areas are located outside the region. The condor is endangered by disturbances of nesting areas rather than inadequate food supply.

Major Uncertainties

Air quality impacts associated with steam generation may impede the use of thermal recovery methods in California even at the level of 50,000 BPD increased production. The 200,000 BPD case is unfeasible due to resource limitations and to air quality, but could be achieved nationwide. The proposed Underground Injection Control (UIC) Regulations could impact enhanced recovery operations by increasing the cost of construction and maintenance as well as increasing the degree of environment protection.

Long-Term/Cumulative Effects

Fluid injection can result in degradation of groundwater quality in the long term. This would be of greater concern in areas having better groundwater quality than Kern County. Air quality will undergo cumulative degradation due to steam generator emissions, especially of SO_2 and NO_x.

Both oil shale production and enhanced oil recovery will result in cumulative air quality impacts, but EOR will not generate the large volumes of particulate matter associated with oil shale crushing, transportation and storage. Socioeconomic impacts would be less for EOR due to predevelopment. However, the estimated potential oil reserves recoverable by EOR (51 billion barrels)[21] are much lower than the estimated, recoverable shale oil (600 billion barrels total). EOR has the potential to provide an alternative liquid fuel supply in the near- to mid-term, while oil shale is a mid- to long-term alternative.

5.1.5 OCS Production

Oil is produced from the Gulf of Mexico Outer Continental Shelf from conventional bottom-fixed steel platforms. The two reference cases, as discussed in Chapter 3, are based on average industry production figures. The 50,000 BPD case assumes three platforms and recoverable reserves of 105 million barrels, whereas 11 platforms and 385 million barrels are assumed for the 200,000 BPD case. Actual development would depend on the specific site and reserves to exploited.

Impact of Oil Spills in the Marine Environment

Two major sources of pollution from OCS production may cause environmental degradation: oil spills and chronic emissions from routine OCS operations. Chronic emissions are more easily quantified than pollution from oil spills and are discussed in detail later. Oil spills cannot be predicted, although spill probability can be estimated.

An analysis of oil spills of more than 1 barrel from 1971 through 1975 reveals that 97.8% of the spills were of less than 50 barrels of oil. The remaining 2.2 percent of the spills accounted for 92.2% of the volume of oil spilled. Out of a total Gulf of Mexico production of 1.811 billion barrels in this five-year period, 50,143 barrels were spilled. This amounts to 0.0028% of the oil produced.[22] The Department of Interior projects that for 790 million barrels of oil which may be produced as a result of the 1980-1985 Gulf of Mexico lease sales, there probably will be 3.29 spills of at least 10,000 gallons (238 barrels) each during the production life of the reserves.[23] This estimate is based on the amount of oil to be produced and the mode of transportation (pipelines) to be used. Extrapolating from this information, it can be projected that 0.437 and 1.60 spills of greater than 238 barrels are likely for the 50,000 and 200,000 BPD cases, respectively.

The environmental impact of oil spills varies considerably, depending on the nature of the spill, the transport and behavior of the spilled oil, and whether the oil contacts vulnerable resources. If spills result from blowouts at the surface, large amounts of oil components will evaporate into the atmosphere. For example, if oil is spilled beneath the surface from a ruptured pipeline, much of the oil would be taken into the water column. If oil is spilled at the surface it may form slicks which cover a considerable surface area. The rate of discharge and duration of the spill also determine the types of effects the spill will have. Spill transport depends upon such factors as location, meteorological conditions, currents and tides. These factors, as well as the location of vulnerable resources, will determine how much damage is caused by the spill. Weather conditions and the nature of the spill also will have a significant effect on the efficiency of spill cleanup. Analysis by the Bureau of Land Management (BLM) shows that Gulf resources such as birds, endangered species, and fish and shellfish are moderately sensitive to oil spills. Non-endangered marine mammals in the Gulf have a low sensitivity to oil spills.[23] The likelihood of oil spills from the reference case contacting vulnerable resources cannot be projected at this time. BLM performs oil spill trajectory analyses for specific sites when they are proposed for leasing.

Air Quality Impacts

Air emissions from OCS operations, disregarding emissions from spills and well fires, are presented in Table 5-7. These emissions result primarily from fuel combustion for power generation, and oil storage and processing and are uncontrolled. USGS regulations promulgated on March 7, 1980 (45 FR 15128) established exemption formulae to determine whether a rig is subject to pollution control requirements, based on estimated emissions and the distance from the rig to the shore. Based on these formulae and projected emissions, controls would not be required if the platforms were 13.6 miles or more offshore. It is assumed for this discussion that reference case production occurs at sufficient distance from the coast to allow uncontrolled emissions. If operations were near coastal areas with poor air quality, controls probably would be required. Air emissions also may result from well fires or oil spills. If a gas blowout were to occur, methane and other light hydrocarbons would be released as well as potentially toxic amounts of hydrogen sulfide. Natural gas combustion is essentially complete so that if it burned only CO_2 would be produced. Oil combustion in an oil well fire generally is incomplete and therefore quantities of volatilized petroleum, particulate carbon, carbon monoxide, nitrous oxide, sulfur monoxide, and other partially oxidized matter would be released in addition to carbon dioxide, sulfur dioxide, and nitrogen dioxide.[24] Sulfur dioxide emissions would not be very high because Gulf crudes have a sulfur content which ranges from 0.1 to 0.5%. If spilled oil were released at or above the water surface, considerable amounts of crude volatiles would be evaporated. Evaporation of as much as 15% of total oil spilled has been observed.[24]

Table 5-7. Average Daily Air Pollutant Emissions From OCS Drilling and Production[25]

Production (BPD)	CO (TPD)	HC (TPD)	NO_x (TPD)	SO_2 (TPD)	Particulates (TPD)
50,000	0.512	3.72	2.75	0.167	0.0340
200,000	1.88	13.6	10.1	0.608	0.125

Air quality in the Gulf OCS generally is very good and OCS emissions should not have any serious impact on air quality. Those coastal counties with major urban centers have air quality problems which emissions from OCS operations could aggravate. The most serious air quality impacts would result from large spills or oil fires.

Existing onshore processing facilities in the Gulf of Mexico are sufficient to handle new Gulf oil production. Therefore, emissions from onshore storage and processing facilities are not considered.

Water Resource Impacts

OCS operations discharge oil and grease from routine operations. EPA standards for new OCS sources limit oil and grease discharges in produced water to an average of 30 ppm. Treatment equipment on platforms in the Gulf has been able to reduce oil content in water discharges to 25 ppm. Up to 0.6 barrels of formation water are produced per barrel of oil. The average total dissolved solids content of formation waters produced offshore of Louisiana is 110,000 ppm as compared with 35,000 ppm for normal seawater. The dissolved components of the produced water have been found to dissipate very rapidly even in shallow water and therefore do not significantly affect water quality. Some toxic metals have been found in formation waters in concentrations greater than in sea water but the concentrations do not appear to be significant.

Water quality will be affected by the disposal of solid wastes such as drilling muds and cuttings. These materials are discharged from the platform into the water. Approximately 39,000 cubic yards (82,000 tons, assuming an average density of 2.5 g/cc) of drill cuttings and 75,000 tons of drilling mud will be disposed of in the first year from the three platforms of the 50,000 BPD case. Cuttings and mud from drilling a single well could be expected to produce a turbidity plume extending over a mile in length, depending on weather and water conditions.[24] If 21 wells are drilled consecutively from one platform, a turbidity plume would be present for more than 500 days. Large quantities of sediment also are suspended during pipeline placement and burial. These sediments may affect benthic organisms adversely by burying them.

Oil spills can introduce large quantities of organic compounds into the water column. Large volumes of water ultimately dilute the oil as it is dispersed. The oil is degraded over time by microorganisms and chemical weathering. In shallow areas oil may become entrapped in bottom sediments and be resuspended during storms.

Past Gulf OCS operations indicate that although short-term water quality impacts may be severe, oil production does not have significant long-term adverse effects on water quality.[24]

Solid Waste Impacts

Drilling muds and cuttings are produced as solid wastes from OCS operations and are discharged into the Gulf from production platforms. This disposal results in increased turbidity as noted earlier. Such disposal also may have adverse effects on benthic organisms. This is especially significant in productive hard-bottom areas such as coral reefs. BLM usually imposes restrictions on solid waste disposal and/or platform siting in productive hard-bottom areas to minimize these adverse impacts.[24]

Land Use Impacts

Approximately 5 acres will be required to provide a navigational buffer zone around each platform.[24] This will temporarily remove 15 acres and 55 acres of water and seafloor from commercial fishing for the 50,000 BPD and 200,000 BPD cases, respectively. Platforms are removed when production ends and wells are plugged below the sea floor. Additional land should not be required for onshore support, storage, or processing facilities because adequate facilities already exist in the Gulf area. Additional onshore land could be required if extensive development took place in the eastern Gulf because this area does not currently support much OCS activity.

Occupational Health and Safety

From 1970 through 1976, 102 fatalities and 162 injuries were associated with Gulf OCS operations resulting from blowouts, fires and explosions, and miscellaneous accidents such as falls, drowning, and being struck by falling objects.[24] Total oil production during this time period was 2.6 billion barrels. Exposure to crude oil also may pose a risk to health due to the carcinogenic potential of components such as polycyclic aromatic hydrocarbons (PAH) found in crude oils.

Ecosystem Impacts

OCS oil production will affect the Gulf of Mexico ecosystem. Low levels of oil and grease in the immediate vicinity of platforms could have some chronic effect on aquatic populations, but the actual effects are not well understood. Platforms will serve as artificial reefs and thus will dramatically increase local marine productivity. Reef areas generally show a marked increase in occurrence and diversity of species. Large, free-swimming fish are attracted to platforms within a few days, and smaller organisms accumulate over longer periods of time. For this reason, platforms attract much of the sport fishing in the Gulf. The most serious ecosystem effects which will be associated with OCS development will result from oil spills.

Spilled oil may persist in the aquatic environment for several years. Volatile aromatics are highly toxic and other low-boiling hydrocarbons may also be toxic. Oil from a spill may have acutely toxic effects which result in the death of organisms, or it may produce sublethal toxic effects. Lethal effects generally result from the oil interfering with such cellular and subcellular processes as membrane activities. Sublethal effects can be of a similar nature and can affect behavior, increase susceptibility to disease, reduce photosynthesis and fertility, and cause abnormal development. The effects ultimately may affect the survival of individuals and may change population dynamics and equilibria.[26]

Hydrocarbons may be ingested by most marine organisms. The chronic effects of such incorporation of hydrocarbons, and specifically carcinogens, are not well understood, but are a cause for concern. Concern has also been expressed regarding the potential for accumulation of these compounds in the food chain, as has occurred, with chlorinated hydrocarbons. Evidence indicates that this will not occur although no firm conclusions can be drawn at this time. Although it has been found that oil spilled in a salt marsh accumulates in almost all organisms in the marsh, some species recover completely from the hydrocarbon contamination with time.[26]

Weathered, high boiling fractions of oil may affect individuals and populations by coating organisms with oil. Birds are especially susceptible to coating, the oil fouling their feathers, causing loss of their ability to fly, keep warm and float. The birds may suffer toxic effects from ingesting oil. Diving duck populations are most susceptible to oil spills as they seem to be attracted to slicks. Oil may affect marine mammals by coating respiratory passages and fouling baleen plates. Ingestion of oil and organisms contaminated by oil could have toxic effects. Adverse effects on individuals, if they occur, may significantly affect marine mammal populations due to their limited occurrence and distribution.[24] Coating should not be a problem for benthic organisms, except those in the tidal zone, although these organisms probably will ingest oil because they are usually filter feeders.

Oil spills generally do not have significant effects on free-swimming organisms such as fish and shrimp because they can avoid oil slicks. Flavor tainting may occur through ingestion of contaminated organisms although widespread tainting of fish and shrimp catches has not been observed in the Gulf. Oil spills, however, may have significant impact on fish larvae because they are not highly mobile and are much more sensitive to toxic effects. Large portions of a year class may be affected in the location of a spill, reducing the population in future years. This type of effect is most significant when spills reach estuarine spawning grounds and nurseries. These areas support exceptionally productive communities and are highly susceptible to oil spill damage.

Major Uncertainties

It is difficult to predict the environmental effects which will result from oil spills except on a site-specific basis which incorporates tides, currents, weather conditions, and the location of vulnerable resources.

Site-specific spill trajectory analyses can be used to estimate the probability of oil spill occurrence and transport once a specific site has been chosen.

Long-term Cumulative Impacts

Low-level releases of air and water pollutants may have very localized effects on air and water quality and may have chronic effects on biological communities. Oil spills may significantly affect air and water quality and biological communities in the area of a spill. Spilled oil may persist in an area for several years and may shift species composition and distribution away from habitats rendered unsuitable by oil contamination.[26]

5.1.6 Coal Liquefaction by SRC II

SRC II is a non-catalytic hydroliquefaction process which produces fuel oil from coal, with byproducts of liquid butane, LPG, SNG, sulfur and ammonia. The discussion which follows assesses the impact of two production levels: 50,000 BPD and 200,000 BPD. These levels would require the input of 16,700 TPD and 66,800 TPD of coal respectively. The reference case is located in Monongalia County, West Virginia.

Air Quality Impacts

Air quality impacts associated with coal liquefaction include (1) particulate generation from the mining, transportation, and preparation of coal; (2) plant emissions of criteria pollutants (SO_x, NO_x, HC, CO and particulates), sulfur compounds, organics and trace elements; and (3) hydrocarbon emissions from product storage and transportation.

The reference case plants are supplied by Pittsburgh coal produced in underground mines. Mine vents emit hydrocarbon gases (chiefly methane) and particulates. Methane may be released or flared. Particulates are generated by coal transportation and preparation as well. Spraying of water or polymers can be used to partially control these emissions.

The liquefaction plants will produce a number of emissions requiring control. Among these are SO_2, NO_x, HC, CO and particulates. Table 5-8 summarizes plant-wide emissions (with controls) of these pollutants for the two reference case production levels. The summary includes those emissions generated by coal preparation at the SRC II plant site.

Table 5-8. Emission of Criteria Pollutants From SRC II

Fuel Oil Production (BPD)	Emissions[27] (TPD)				
	SO_2	NO_x	THC	Part	CO
50,000	4.5	8.7	0.5	2.2	0.7
200,000	18.0	34.8	2.0	8.8	2.8

These emission levels could have a significant impact on regional air quality. The most significant criteria pollutants emitted are SO_2 and particulates. Several counties adjacent to Monongalia County exceed the primary air quality standards for these pollutants. Modeling results for a proposed 14,000 BPD SRC II plant in Monongalia County indicate that 94% of the available PSD increment for total suspended particulates would be used up by this plant.[28]

In addition to the criteria pollutants, liquefaction plant emissions may contain trace metals and organometallic compounds, polynuclear aromatic hydrocarbons (PAH), aromatic amines and heterocyclic sulfur compounds. These materials may have long-term cumulative impacts on public health at low levels of exposure.

The storage and transportation of hydrocarbons can result in their release into the atmosphere due to evaporation, spills and leaks. Fugitive emissions from the liquefaction operations would also release hydrocarbons. Hydrocarbons combine with NO_x in the presence of light to form photochemical oxidants. The estimated hydrocarbon emissions from a proposed 14,000 BPD plant are small in comparison to the background levels in Monongalia County.[28] However, the background ozone levels for the area are sufficiently high that a small increase in hydrocarbon emissions could result in violation of NAAQS primary ozone standards.

Water Resource Impacts

The SRC II plants would require a water input of 238,094 BPD (10,066 acre-ft/year) for the production of 50,300 BPD, and 952,376 BPD (40,264 acre-ft/year) of water for the production of 201,200 BPD. Water availability could potentially impede the development of liquefaction facilities at the reference production levels. Surface water is the primary industrial water source in the region.

Water pollution impacts may occur as the result of mine drainage, accidental liquefaction plant discharges or leaching from solid waste disposal sites. Acid mine drainage has already caused severe water quality degradation in the Monongahela and other West Virginia rivers. The reference cases would require the underground mining of 16,700 to 66,800 TPD of coal. The mining effluents associated with these production levels are shown in Table 5-9.

Table 5-9. Coal Mining Wastewater Effluents, Underground Mining[29] (TPD)

	Coal Production Level	
	16,700 TPD	66,800 TPD
Total Iron	13.5	54.0
Suspended Iron	3.23	12.9
Dissolved Iron	10.3	41.2
Manganese	0.280	1.12
Aluminum	1.67	6.68
Zinc	0.0560	0.224
Nickel	0.0276	0.110
TDS	182.	728
TSS	8.73	34.9
Hardness	46.9	188.
Sulfate	91.4	366
Ammonia	0.460	1.84
Strontium	0.0935	0.374
Chloride	3.96	15.8
Fluoride	0.0524	0.210

The SRC II reference case plants are assumed to have a zero discharge design. All wastewater, including boiler and cooling tower blowdown water and process water is treated and recycled in the plant. Water which is too concentrated for reuse is evaporated in lined ponds. Surface and groundwater impacts could result from equipment leaks, leaks in evaporation pond liners, flooding of evaporation ponds during frequent downpours, or other accidental spills. Liquid wastes generated by the liquefaction plants will contain a number of hazardous substances, such as ammonia, hydrogen sulfide, toxic trace metals, phenols, aromatic hydrocarbons, thiophenes, aromatic amines and other organic compounds.[29] The accidental release of these compounds into surface water or their percolation into groundwater could seriously degrade the water quality and threaten aquatic and land species.

Another potential source of water contamination at the plant site is leaching of hazardous materials from solid waste disposal areas. Solid wastes such as coal ash, coal refuse and sludges from pollution control devices contain hazardous substances which could degrade water quality. This problem also is present in the oil shale alternative, although the volume of spent shale generated is considerably greater than the solid wastes produced by liquefaction.

Solid Waste Impacts

Coal liquefaction plants will generate large volumes of solid wastes requiring disposal. The largest solid waste stream from the plant would be the gasifier slag stream. Other solid waste streams include tramp iron and coal refuse, sludge from tailing ponds and water treatment modules, mineral ash, and oxidized solids from incineration of wastewater treatment residues.[29] The 50,000 BPD facility would generate 6,890 TPD of solid waste and the 200,000 BPD facility 27,560 TPD.

Solid wastes can impact the environment directly by affecting land use options and changing land contour and surface vegetation. They can have indirect impacts on the air due to wind erosion, and water, due to leaching.

Both liquefaction and oil shale production create large volumes of solid wastes, although oil shale operations produce a greater volume of solid wastes per barrel of oil produced.

Land Use Impacts

Coal mining can impact land use by causing subsidence or by damaging surface vegetation through mine runoff. Liquefaction plants (process area and coal storage only) will require approximately 400 acres of land for the 50,000 BPD production case and 1,600 acres of land for the 200,000 BPD production case. The disposal of solid wastes would require the commitment of 250 to 525 acres for the 50,000 BPD production level, and 1,000 to 2,100 acres for the 200,000 BPD production level.[29]

Ecosystem Impacts

Mine runoff has an adverse impact on aquatic ecosystems, and also may affect land animals depending on the affected waters. Surface waters in the reference case area are already badly degraded due to mine runoff. The hazardous substances associated with liquefaction, such as PAH, toxic trace elements, and various organic chemicals could result in adverse long-term effects on animal and plant populations if released into the environment by air emissions or accidental liquid or leachate discharges. Significant increases in water consumption could impact aquatic ecosystems during low-flow periods.

Health and Safety Impacts

The most significant potential health impacts of coal liquefaction are those related to chemical hazards. Known and suspected carcinogens have been identified in coal conversion process streams, including various polycyclic aromatic hydrocarbons (PAH), hetero- and carbonyl-polycyclic compounds, aromatic amines and inorganic trace elements.[30]

Severe operating conditions such as high temperature and pressure tend to result in the formation of polycyclic organic molecules, many of which are considered hazardous. Since liquefaction processes use more severe operating conditions than the production of shale oil, petroleum or biomass-alcohol, it may be inferred that the potential for hazardous chemical formation is greater for the liquefaction alternative. This seems to be supported by a study being performed by E.I. du Pont de Nemours and Co., Inc. for DOE, which compares the health effects of various synthetic crude oils. Preliminary results indicate that coal-derived liquids show a greater hazard potential than shale-derived liquids, which in turn are more hazardous than petroleum fractions. These findings are based on mutagenicity and tumor initiation tests.[31] (The study tested H-Coal materials rather than SRC-II liquids.)

Industrial workers in liquefaction plants may be exposed to hazardous chemicals in the work environment by inhalation or dermal exposure. Low-level exposure over long periods could impact employee health. The release of low levels of these substances into the ambient air could have long-term effects on public health in the surrounding region. Public health also may be impacted by contamination of surface or groundwater by hazardous substances. Several process chemicals, such as certain types of polycyclic organics and arsenic, are believed to be cancer agents.

Workers may be exposed to safety hazards associated with high temperature and pressure operations, the use of heavy equipment, fire and explosion hazards, and equipment failure. Due to the developmental nature of the technology, data are not available to quantify these hazards.

Major Uncertainties

The adequacy of wastewater control designs to clean produced waste waters effectively is uncertain. The effectiveness of lined evaporation ponds for the containment of hazardous waste waters is uncertain due to the possibility of liner failure and flooding. Six or more inches of water have fallen in a 24-hour period in the region. Air emissions such as sulfur compounds and condensible tars may undergo chemical reactions after emission, posing uncertain health risks. The ability of trace element control devices (such as those used by the electroplating industries) to effectively control these pollutants in a hydrocarbon air stream is uncertain.[29] Organic compounds present in liquefaction processes require further health effects testing.

Long-Term/Cumulative Impacts

Long-term degradation of air and water resources may result from the various effluents of the mining and liquefaction of coal. Of particular importance is the problem of long-term exposure to potential carcinogens in plant emissions and products, which may have adverse affects at low levels.

5.1.7 Biomass: Ethanol Production in Central Illinois

The following section discusses the environmental impacts of ethanol production from corn based on a plant design by R. Katzen Associates.[32] The first reference case is for 14 plants to be located in central Illinois, producing 50,500 BPD of ethanol. The second case is for 56 plants which would produce 202,000 BPD of ethanol. The 14-plant case would require an input of 824,600 bushels of corn/day and would burn 4,155 TPD of Illinois No. 6 coal for process heat (i.e., for cooking the mash, fermentation heat and other plant processes). The 56-plant case would require 3,300,000 bushels of corn daily, and would burn 16,620 TPD of coal.

The barrel-for-barrel equivalence of ethanol to petroleum was set arbitrarily, as the simplest case, which can be scaled as desired. If a Btu equivalence is desired, then the ethanol plant would need to produce about 60% more (using gasoline equivalency) or from 65 to 90% more (using petroleum equivalency). A case can be made for either. If vehicle-miles is used as the equivalence criterion, then the Btu ratio would be appropriate, provided the demand-price elasticity effects are neglected. In any event, a larger ethanol production capacity would result, and the emissions and residuals would be increased proportionately.

Air Quality

The burning of coal for steam generation would be the most significant direct source of air emissions. Quantitative data on other sources of plant emissions are not available. Some emissions of light hydrocarbons could be expected from the fermentation and distillation processes. Particulate emissions should not be high because a wet milling process is used. Estimated air emissions for the 14-plant and 56-plant cases are shown in Table 5-10. If 95% removal is assumed, SO^2 emissions would be reduced to 7.3 and 29.2 TPD for the two cases. Particulate emissions would be negligible because of filtration which will remove particles down to 1 micron.

Table 5-10. Biomass/Alcohol Emissions

No. of Plants	Ethanol Production (BPD)	Coal Burned (TPD)	Emissions[33] (TPD)		
			SO_2 (TPD)	CO_2 (TPD)	Particulates (TPD)
14	50,500	4,155	7.3	7,472	Negligible
56	202,000	16,620	29.2	29,888	Negligible

Several urban areas in central Illinois violate NAAQS standards for SO_2. Particulate standards are violated in a number of counties in the region. Emissions from coal-fired boilers would require controls to prevent damaging air quality impacts. The release of large volumes of CO_2 into the atmosphere is believed to have the potential for causing global climatic changes.

Indirect emissions associated with ethanol production from corn include particulate generation from agricultural activities and coal mining. The amount of pollutants generated from these non-point sources is difficult to determine. Control methods such as spraying of dust-generating areas would mitigate the impacts to a degree.

Water Resources and Impacts

Ethanol production is a water-intensive process. The 14-plant case would require 3.5 million GPD (3,587 acre-feet/year) of make-up water for the production plants alone. The 56-plant case would consume 14 million gallons/day (14,348 acre-feet/year). Although Illinois as a whole has an abundant water supply, water occurrence is sporadic. Several central and southern parts of the state do not have sufficient quantities of groundwater to support even a single 3,600 BPD facility. Additional surface reservoirs would have to be constructed if surface waters were used. This area has a history of public opposition to reservoir construction. While groundwater supplies could accomodate the 50,000 BPD case reasonably well, the 200,000 BPD case may tax available supply and compete with other uses.[34] In either case, water supply will be a determining factor in selection and distribution of plant sites. Some aquifer drawdown may accompany development, although in areas where groundwater is plentiful it is largely underdeveloped.

Corn production is also water-intensive. No major impacts on water resources are expected to result, however, since the humidity of central Illinois is sufficient in an average year to provide for 83 bushels/acre production levels.

Wastewater from the ethanol plants would require biological treatment before being discharged into surface streams. The volume of wastewater requiring treatment and discharge would be approximately 15.4 million GPD for the 14-plant case, and 62 million GPD for the 56-plant case. Such large volumes of effluent may pose problems in the region inasmuch as reaches of the rivers in central Illinois are dry or nearly so for significant portions of the year. Water for dilution of treated effluents may be quite limited, resulting in adverse effects on water quality. Discharges during periods of low flow may also have a beneficial effect by stabilizing water flows.

Impact on water quality would also result from non-point sources supplying corn and coal for plant operation. Agricultural and coal mine runoff are the primary sources of water degradation in Illinois. Agricultural runoff increases stream siltation and contributes pesticides and nitrogenous fertilizers to the aquatic environment. The fertilizers accelerate eutrophication, resulting in bad tastes and odors in the surrounding waters. Runoff from coal mines and coal storage piles at the plant would contribute acidic water to freshwater streams. Non-point sources of pollution are more difficult to control than point sources.

Solid Waste Impacts

Coal ash would be generated by the coal-fired boiler units at the rate of 384 TPD for the 14-plant case, and 1,536 TPD for the 56-plant case. Coal ash requires proper disposal or recycling to prevent leachate contamination of surface and groundwaters. Ethanol production will produce significant quantities of two marketable byproducts. Distiller dark grains can be sold as animal feed. The 14-plant case will produce 7,514 TPD of the byproduct. Ammonium sulfate, which could be sold as fertilizer, would be produced at a rate of 442 TPD (14-plant case). The sale and use of generated solid "wastes" is a positive environmental characteristic of ethanol production.

Coal mining will produce overburden and fines requiring proper disposal or reclamation procedures to prevent adverse land and water impacts. Air and water pollution control methods will produce sludges at the plants. Sludges from biological water treatment may be used as fertilizer if properly treated. Scrubber sludges from flue gas desulfurization can impact water quality if proper disposal procedures are not followed. Oil shale production will produce much larger volumes of solid wastes (e.g., spent shale) than ethanol production and supporting activities. Wastes from ethanol production are generally less hazardous than oil shale solid wastes, and have a greater potential for recycling.

Land Use Impacts

Ethanol production is a land-intensive process. Illinois has a relatively high average production ratio of 83 bushels of corn per acre. At this rate the 50,500 BPD case would require 5,000 square miles of usable agricultural land for corn production. The 202,000 BPD case would require 20,000 square miles of land. This is considerably more land area than would be required for oil shale production; however, the agricultural land can be used for the same purpose year after year, and can be converted to other uses relatively easily. Agriculture is already the prime land use in central Illinois, utilizing approximately 90 percent of the land in most counties.

Coal mining and the production plants themselves also would affect land use. They would impact much smaller areas than agriculture, but would commit the land to energy production for longer periods of time. Reclamation of mined lands is necessary both for the production of oil shale and coal; however, the humidity of the central Illinois climate would make reclamation easier than in the more arid West.

Other land use impacts include increased erosion from agricultural and mining activities, and possibly the subsidence of the land surface due to mining.

Health and Safety

No unusual health and safety impacts are expected from ethanol production. Typical mining hazards would be associated with coal operations supporting the ethanol plants. Machinery and pesticide hazards would affect the supporting farms. Ethanol plant workers would be subject to normal industrial safety hazards such as machinery accidents and fire. The presence of flammable liquids increases the probability of fire or explosions. Hydrocarbon fumes (e.g., from gasoline and ethanol) would require in-plant controls to prevent exposure or explosion. Safety risks associated with ethanol fermentation and distillation are expected to be less serious than those posed by other technology alternatives due to less severe operating conditions, although data to substantiate such a safety comparison are not available.

Ecosystem Impacts

The only significant ecosystem impact of ethanol production would be changes in plant and animal (especially insect) populations resulting from changes in traditional crops and land uses. This effect would be small in central Illinois since corn already is a major crop. Degradation of air and water quality from ethanol production would have a cumulative effect on the health and distribution of plant and animal species. The increased use of pesticides would affect insect and bird communities and potentially could affect animals further up the food chain, including humans.

Major Uncertainties

A major uncertainty in assessing the impact of ethanol production is whether the coal and corn used for ethanol plants will come entirely from new production or by diversion of the products from existing destinations. Although for the sake of comparison it must be assumed that the feedstock will come from new production, in reality corn supplies may be obtained by decreasing exports or from surpluses normally kept off the market to protect prices, rather than from increased acreage. Many of the impacts discussed above would be mitigated to the extent that current production levels and practices were used to supply the plants.

The extent to which non-point sources of air and water pollution would impact the environment are difficult to assess quantitatively. It is known however, than non-point agricultural and coal mine runoff--two of the impacts associated with ethanol production--already are causing degradation of water quality in central Illinois.

Long-Term Impacts

Although corn is a renewable resource, its production and conversion to ethanol requires the use of non-renewable resources, including coal, chemical fertilizers, lime, etc. The continued erosion of land and siltation of surface waters is accelerated, but not caused solely by agriculture. Its long-term effects will be to decrease land productivity and diminish stream flow.

The accumulation of pesticides in surface water, groundwater, and the food chain due to agricultural runoff could have adverse, long-term effects on the plant, animal and human population, provided new land is cultivated. Air emissions will have a cumulative effect on air quality. Carbon dioxide emissions may contribute to long-term climatic changes on a global scale.

5.2 SOCIOECONOMIC CONSEQUENCES

The discussion of socioeconomic impacts is divided into three subsections. An overview of socioeconomic effects and the analyses performed for the EIS is presented in the first (5.2.1), comparative analysis of socioeconomic effects associated with a nominal 50,000 BPD production level by NOSR 1 and the five alternatives addressed in this EIS is presented in the second (5.2.2), and analysis of the cumulative effects of NOSR development in western Colorado is provided in the third (5.2.3).

5.2.1 Overview

Large-scale energy development tends to generate rapid and discontinuous changes in the social and economic environment of rural commmunities. There are basically five components of this energy-based socioeconomic transformation as it has occurred throughout the country.[35]

1. SOCIAL DISRUPTION. Energy develoment causes sudden changes in the population mix and patterns of everyday life. These in turn cause social problems and social conflicts. Rates of alcoholism, drug abuse, mental illness, divorce and juvenile delinquency increase. While many of these problems are experienced by newcomers unaccustomed to their living conditions, long-time residents are similarly affected by the disruption.

2. PUBLIC SERVICE NEEDS. Americans have come to expect certain basic public services such as roads, water, schools, police and fire protection, and social welfare assistance. During rapid growth, these services are often overburdened, or unavailable to some groups. In addition, public services which a small community did not provide before may be necessary to support energy develoment to cope with its side effects. Tax rates must often increase to cover the cost of providing new or expanded services. The lead time needed to design and build new facilities may mean that the costs are borne by those who live in the area before the boomtown population has actually arrived.

3. SHORTAGE OF PRIVATE GOODS AND SERVICES. During a rapid growth period, the private market rarely keeps pace with demands for goods and services, especially housing. In some cases, housing shortfalls actually can restrict energy development and worker productivity.

4. INFLATION. Excess demand triggers inflation in prices, wages and rents. While price increases may be welcomed by the storeowner whose costs usually do not rise as quickly as revenues, and increased housing prices benefit the landlord, inflation is particularly harmful to senior citizens and others on fixed incomes who cannot take advantage of rising wages. High construction wages, combined with a general labor shortage, also may cause other wages in the local economy to rise.

5. REVENUE SHORTFALLS. Even though growth expands sales and property tax bases, revenues may increase more slowly than costs in the short run. These revenue shortfalls are due to (i) delays between the time development begins and the time a locality may realize either property or sales tax revenue; (ii) delays in raising capital for constructing and improving public facilities; (iii) capital needs beyond local government's legal bonding capacity; and (iv) location of high-tax yielding properties outside the communities hosting the newcomers and the resulting public costs.

These adverse effects have typically been more pronounced in regions where energy development is a totally new and unprecedented influence, and in this regard the development of oil shale at NOSR 1 and the alternatives of coal liquefaction and private commercial shale development all share the potential of generating major socioeconomic change while the development alternatives for which a certain body of precedent experience exists (enhanced oil recovery, Outer Continental Shelf oil production, and gasohol) are unlikely to present as severe an intrusion or impact on their respective socioeconomic environments.

For purposes of this analysis, quantitative estimates of the beneficial and adverse economic effects of each alternative development configuration have been derived; and where possible a general discussion of the anticipated social implications of each particular development under study is provided. The economic measures selected here reflect a public benefit/cost perspective and include the following:

1. Property tax effects (i.e., revenues) of constructing and operating the relevant facility or facilities;
2. Residential property tax effects (i.e., revenues) associated with the construction and operational work forces;
3. Local sales tax effects of work force wage and salary expenditures;
4. State income tax effects of work force wage and salary payments; and
5. Fiscal impacts on local government due to influx of transient and permanent work forces (i.e., costs associated with construction and operation and maintenance of required new public, capital facilities, including roads, schools and utilities, and community service delivery systems, such as health, police, fire, and education).

These standard public cost and revenue categories provide a uniform basis for assessing the comparative economic impacts of the alternative technologies under study. The social effects of the individual development options are more difficult to anticipate since comparable quantitative measures are non-existent. Considerations of potential social and community change are thus treated only in a general way. Several other qualifications to this analysis also need to be noted.

The comparative analyses do not derive from a precise year-by-year modeling of the socioeconomic effects of each development option, and no site-specific baseline analysis has been conducted. Various assumptions necessarily have been made regarding local government tax structure and public service delivery systems. No explicit analysis of existing capacity in public facilities and services has been included, and thus all cases tend to present a "worst case" impact profile. Of particular importance is the fact that planned or in-place mitigation measures, both local and federal, have not figured in the overall comparative analysis. For example, it should be recognized that in recent years the State of Colorado (the location of both the NOSR 1 and private oil shale development option) has been developing a progressive and comprehensive program to assist communities which will be affected by oil shale development. Colorado's community impact assistance effort is funded primarily by revenues obtained from the State's Oil Shale and Severance Tax Trust Funds.

Federal policies on inland impact assistance are less clearly defined. There are only three federal programs specifically geared to addressing the problems of energy-impacted communities: the Coastal Energy Impact Program (CEIP); the DOE Farmers Home (Fm Ha) 601 Impact Assistance Program; and the 1920 Mineral Leasing Act which provides the states with up to 50% of revenues collected for federal leasing activities, including federal oil shale lands. The CEIP, while not applicable for oil shale development, could figure prominently in mitigation efforts connected with the OCS and liquefaction development options.

Public Revenue and Cost Categories

Public revenues and costs provide a basic measure of the impact (both beneficial and adverse) associated with each of the development options under study. The configuration of costs and revenues induced by the respective development options has a direct effect on such broad public concerns as the distribution of the public financial burden among citizens; the performance of local markets, including labor, housing, land, consumer goods, services, and transportation; efficiency in the consumption of public services; and local control of future spending and resource allocation decisions.

The revenue sources considered here include the following: retail sales tax, property tax, and state income tax.

Retail sales taxes are commonly separated into two categories: (1) general and (2) selective. Both forms are typically used at the state level. The general sales tax is the form predominantly used at the local level. The general sales tax is typically an excise tax levied on retail sales of tangible personal property in the taxing jurisdiction. Sales of services normally are excluded from taxation at both state and local levels.

For purposes of this study, retail sales tax revenue has been derived from wage and salary expenditures for all project personnel. It has been assumed that net disposable income is equal to 70% of the gross wage and salary income earned by construction and operation work forces and that 50%

of this net income is expended on items subject to tax. It is assumed further that 50% of these taxable expenditures are purchased outside the borders of what would constitute the regional economic environment of the particular development in question. Finally, an assumed sales tax rate of 5% is assumed to prevail in all regional project environments.

The property tax is an ad valorem tax computed on the assessed valuation of all taxable property, real and personal, located within the territorial limits of the authority levying the tax. A basic distinction is made here between the property tax revenue generated by the respective energy facilities identified in each development option and the residential and commercial property tax revenue that would flow from the new housing and business development occasioned by the presence of new work forces and population. The importance of property taxes as a key indicator of socioeconomic impact and as the principal source of local revenue for local governments is illustrated by the fact that nearly 90% of all local tax income normally is represented by property taxes. The added assessed valuation of major energy facilities is derived by applying an average 30% assessed valuation rate to the capital value of the facilities inherent in each development option. An average mill levy of 25 mills has been applied to obtain an estimate of plant based property tax revenue. Again, it should be noted that, while assessment is not normally deferred until construction is completed, no incremental or phased analysis of property tax revenue has been undertaken.

Residential property tax revenue has been estimated by applying an average per capita factor of $75 to the new population fostered by the direct work force and induced employment associated with each development option.

State income tax revenue effects of each development option have been estimated by applying a uniform 5% rate to the gross wage and salary income of direct and induced work forces. Conservative estimates of direct project personnel wage and salary income and local service employee income have been utilized. The respective estimates of gross annual income for direct project personnel and induced or local service workers are $20,000 and $15,000 (1980).

Two aggregate local government per capita cost factors have been utilized to estimate the total costs for new capital facilities and human services that would be required for the population growth engendered by each development option. These per capital cost factors were derived by reviewing selected operations and maintenance and capital construction budgetary data from representative local governments throughout the country. An average 1980 local government capital cost factor of $800 per capita was applied to the new population associated with each development option to obtain a total local government capital cost estimate. Similarly, a per capita cost factor of $600 for expanded human services delivery was utilized to derive a comparable total cost estimate for that category.

The comparison of cost-revenue impacts of the various alternatives is based on peak operation employment and the population which it induces. Although construction impacts would be significant, they are discontinuous and not representative of the long-term balance between the costs and revenues attributable to the various energy development alternatives. The cost-revenue comparisons represent a typical year of development operation and present the average total annual costs and revenues generated by the induced population.

5.2.2 Comparative Socioeconomic Impacts of Development Options

This subsection provides a comparative analysis of the social and economic effects that would be associated with a 50,000 BPD production level at the NOSR 1 site and the realization of equivalent production at five alternative sites utilizing the following alternative technologies:

1. Commercial Oil Shale Development, utilizing TOSCO II processes (i.e, the Colony development in western Colorado);
2. Coal Liquefaction, utilizing SRC II process near Morgantown, West Virginia;
3. Enhanced Oil Recovery, utilizing steam injection processes in Kern County, California;
4. Outer Continental Shelf oil production in the Gulf of Mexico or in southern California; and
5. Grain fermentation to produce ethanol for use in gasohol production in central Illinois.

Each alternative will be discussed below. All developments are viewed in isolation with no concomitant development assumed. An assessment of the cumulative effects of NOSR and other energy projects in western Colorado is provided in 5.2.3. There are no measurable socioeconomic impacts of the conservation alternative and, consequently, no discussion is included in this section. See the reasons for selection in Section 3.2.

NOSR and Colony Regional Description

The regional vicinity of the NOSR and Colony developments may be viewed as encompassing Garfield, Rio Blanco, and Mesa Counties in western Colorado. This three-county area is part of the great Colorado Plateau and is dominated by the Colorado River and a preponderance of national forest and other federally managed lands.

Municipalities of importance in the region include: Grand Junction, Parachute, Rifle, Glenwood Springs, Meeker, and Rangely. Population data for the region are given in Table 5-11 and reflect the predominantly rural character of the three counties and the rapid population growth experienced during the past decade.

Table 5-11. Regional Population Data

Location	1970 Population	1980 Population
REGION	74,037	110,299
Garfield County	14,821	22,514
Rifle	2,150	3,215
Parachute	270	338
Glenwood Springs	4,040	4,637
Rio Blanco County	4,842	6,255
Meeker	1,743	2,356
Rangely	1,839	2,113
Mesa County	54,347	81,530
Grand Junction	24,043	28,144

The socioeconomic base of the region is supported by agriculture, mining, and tourist-related industries; and land use patterns reflect the region's relatively undeveloped nature.

The oil shale region of Garfield, Mesa, and Rio Blanco Counties in western Colorado has already experienced substantial growth due to coal development and recreation and tourism-based attractions. Table 5-12 summarizes, for example, the population growth of Garfield County and its incorporated areas from 1960 to 1980. The County population as a whole grew by 23 percent during the 60s, or a 2.1 percent annual rate. Only Glenwood Springs and the unincorporated area exceeded that growth rate, with 4.4 and 3.9 percent annual gains, respectively. (Annexations, which may have artificially increased the apparent growth of towns and decreased that of the unincorporated area, are not discounted in the Census data.)

Table 5-12. Population Growth Trends - 1960, 1970, 1980

	1960	1970	1977	1980	Compound Annual % Change 1960 - 1970	Compound Annual % Change 1970 - 1977	Compound Annual % Change 1977 - 1980
Garfield County	12,017	14,821	18,800	22,514	2.1	3.5	6.2
Carbondale	612	726	1,644	2,084	1.7	12.4	8.2
Glenwood Springs	2,637	4,040	4,091	4,637	4.4	0.2	4.3
Parachute	245	270	377	338	1.0	4.9	-3.6
New Castle	447	499	543	563	1.1	1.2	1.2
Rifle	2,135	2,150	2,244	3,215	0.1	0.6	12.7
Silt	384	434	859	923	1.2	10.2	2.4
Unincorporated Area	4,557	6,702	9,042	10,754	3.9	4.4	5.9

Source: U.S. Bureau of the Census, 1960 Census, 1970 Census, 1977 Special Census, 1980 Census (Advance Report)

The 1970 to 1980 period showed a significant change in the trend of the 60s. Glenwood Springs' population growth slowed while Silt's and Carbondale's annual growth rates exceeded 10 percent. Both Parachute and the unincorporated area also exceeded the County's 3-1/2 percent annual rate of change. Newcastle and Rifle experienced moderate but increasing rates of growth.

The employment and population effects of the NOSR or Colony projects will thus be superimposed on an area already experiencing substantial growth.

NOSR Development Options

The development of a 50,000 BPD facility at NOSR 1 in western Colorado will require a peak construction work force of approximately 2,100 persons and a permanent operational work force (including mine personnel) of about 1,200. The overall development schedule is such that mining and operational personnel are introduced prior to the completion of plant construction, and thus the combined peak work force (i.e., initial operational personnel added to the peak construction work force) may be estimated at approximately 2,300 persons. This direct project work force will present a short-term demand for additional local service workers in the region and will foster a discontinuous increase in total population. The long-term operational work force associated with the NOSR development will present a substantial demand for local service employment, and for purposes of this comparative analysis the permanent long-term population effects of the NOSR development provide the basis for the following impact assessment.

The long-term permanent operational work force of 1,200 persons at NOSR 1 will support local service employment totaling about 1,800 persons. This level of induced employment assumes a "multiplier" effect comparable to those identified in the large body of socioeconomic research that has been undertaken in the region. The long-term total population effect (all workers and their related family dependents) of the NOSR 1 development will approximate 7,500 persons. The influx of 7,500 persons in the regional vicinity of the NOSR development will alter substantially the existing socioeconomic environment.

Retail expenditures on the part of direct project personnel and indirect local service workers will generate approximately $440,000 annually in the sales tax revenue.

Projections of the property tax effects of the 50,000 BPD facility at NOSR 1 can be estimated from a capitalized value of $875 million. The plant's assessed valuation would be roughly $263 million yielding about $6.5 million in annual revenue.

Residential property taxes generated by the induced population would total over $560,000 annually. Income taxes generated by project-related employment would total over $2.5 million. Direct project employment would account for $1.2 million, and indirect employment would account for $1.35 million each year.

Total public tax revenues generated by the project would amount to over $10 million annually. Public costs would include $6 million in local government expenditures and $4.5 million for expanded human services delivery. Consequently, the costs of the 50,000 BPD NOSR development could feasibly be offset by revenues generated by project activity.

However, if the project should be government owned and contractor operated, there is a definite prospect that local government could lose the property tax on the facility based on the holding of a recent court case. In United States V. State of Colorado, 627 F.2d 217 (1980), the state was sued by the U.S. over the issue of the taxing authority under Section 39-3-112 of the Colorado Revised Statutes, 1973. At issue was a user tax imposed on Rockwell International Corp., which operated the Rocky Flats Nuclear Weapons Plant, near Denver, which is owned by the federal government. The Court of Appeals ruled in favor of the U.S., holding that the Colorado tax on Rockwell, as the user of tax-exempt property, was in reality a tax on the property itself, and, as such, was barred under the doctrine of implied immunity. This loss of revenue would only be partially offset by the payment in lieu of taxes (PILT) program. Since property taxes on a NOSR oil shale facility account for over half of the potential revenues, the government owned, company operated option would likely create a significant burden on local agencies to accommodate the population influx due to the development.

The amount of government ownership varies among the five development policy options, and the amount of property tax on the facility varies inversely, as listed below.

Option	Government Ownership	Property Tax
Lease	0%	100%
Quasi-utility	0%	100%
Separate Ownership	27%	73%
Joint Ownership	50%	50%
Government Owned	100%	0%

(The loss of tax revenue due to partial government ownership could again be offset in part from the PILT program.)

The 200,000 BPD NOSR option would have significantly greater impacts in the project area. The construction period would be six to seven years longer than the 50,000 BPD option. The overlap of construction and operation activity would magnify the impacts on the socioeconomic environment. The construction peak work force would remain about the same as in the 50,000 BPD scenario but the number of operation workers would increase to an estimated 4,000 employees. Indirect local employment generated by operation activity would amount to about 6,000 employees resulting in a population increment of 23,000 which would constitute an overwhelming increase in baseline population levels.

The increase in population under the 200,000 BPD option would generate over $1.7 million in residential property taxes. Income taxes paid by operation employees would total $4 million annually and indirect employees would account for an estimated $4.5 million in additional state income taxes. Sales taxes generated would amount to approximately $1.5 million annually.

The 200,000 BPD oil shale complex would have an estimated capital value of $3.2 billion and would generate approximately $24 million annually in property taxes under the private lease option. Total revenues resulting from the project would amount to almost $36 million annually.

Public costs would also be substantial due to the massive number of people involved. Local government capital expenditures would be expected to amount to over $18 million per year. The cost of expanding human delivery services would amount to almost $14 million resulting in total public service costs of over $32 million annually. Consequently, the project under the lnease option would likely produce enough revenue to offset the public service costs associated with the project.

However, as in the case of the 50,000 BPD option, if the government owned, company operated option were pursued resulting in a loss of most of the property taxes generated by the project, there would be a major burden placed on local government.

Colony Development Option

The Colony Development would be quite similar to the 50,000 BPD NOSR development in terms of costs and revenues. The estimated construction work force is somewhat larger at 2,400 workers whereas the operation work force of 1,000 to 1,200 is comparable to the NOSR option. The operation activity will generate approximately 1,800 service jobs resulting in a total project-induced population increment of about 7,000.

The new population would generate almost $338 million in residential property taxes each year. Income taxes paid to the state by direct and induced employees would total over $2.5 million per year. Local purchases made by project-related workers would amount to almost $370,000 annually.

The capital value of the oil shale facility would be approximately $1 billion and would generate over $9.5 million in property taxes each year.

Total annual revenues resulting from this project would amount to almost $13 million. Public costs would total almost $9.7 million representing local government capital expenditures of $5.5 million and additional costs of $4.2 million for human services.

The accommodation of the direct and indirect population growth that will be associated with oil shale development in western Colorado will be a critical determinant of the feasibility and ultimate success of any specific project that is contemplated for the region.

The Colony project staff has conducted extensive analyses of the likely land use and settlement patterns that would result from the Colony project in the absence of systematic community development planning efforts. These analyses reveal that the area of significant and direct socioeconomic impact would be the Colorado River Valley between Grand Junction, Colorado, and Glenwood Springs.

A variety of possible urbanization patterns with varying degrees of land use and zoning controls can be postulated, ranging from uncontrolled scattered linear development from Glenwood Springs to Grand Junction to a concentrated new development with a diversified employment base.

Three alternative settlement patterns were selected by Colony for further study of their consequences and offsite impacts. They were (1) expansion of existing communities, (2) scattered growth, and (3) a new community accompanied by some expansion of existing communities.

Existing communities were examined in terms of their growth potential by looking at various factors--developable land; unused school capacity; ability of sewer, water and road networks to expand; fiscal position; community facilities; etc. Grand Junction is western Colorado's major transportation and service center and due to its size and expansion potential, will be impacted to some degree. However, its location is some 50 miles from the town of Parachute and a two-hour, one-way commute to Parachute Creek plant sites. Likewise, Glenwood Springs, another substantial community is some 40 miles to the east of Parachute. Its expansion potential is limited by severe topographic features. The town of Rifle, nearer to the Parachute entry to the southern Piceance Basin, has substantial growth areas, and, notwithstanding limited sewer and water capacities, could accommodate a portion of the direct and indirect population increase.

Uncontrolled fragmented growth would most likely locate itself adjacent to the existing road system, limited to the linear Interstate 70 corridor. This potential growth area has both a highly vulnerable ecological and air quality condition, a highly productive ecosystem from the standpoint of wildlife and a high frequency of natural temperature inversions which could be impacted more severely by emissions associated with increased urbanization and automobile commuting. Some river bottom areas are within highly constricted canyons where air stagnation is even more critical. An uncontrolled scattered urbanization in the region would necessitate long distance automobile-oriented commuting to work locations, contributing pollutants to these areas with poor air dispersion conditions.

Parachute itself and the head of Parachute Creek Valley, although a pleasant south-facing valley with a temperate climate, provide only a restricted area for development. The present checkerboard housing development and ownership pattern of the valley would prevent the siting of any extensive development. Without planning controls, strip growth of piecemeal sprawl would likely result both up and down river from Parachute and up Parachute Creek. Although Parachute is convenient for urbanization in terms of the home-to-work commute, topographic features limit land available for expansion with hills on either side and the river and floodplain to the south. With cold air drainage down the valley from the north, local air pollution could result from both the oil shale development and commuting to it, as indicated by studies of the air quality impacts.

Colony Development is committed to a planned comprehensive new community on the Battlement Mesa south and east of the Colorado River at Parachute, thus restraining the unmanageable growth pressures on Rifle and Parachute without depriving them of a significant portion of the project's economic benefits.

The major planning criteria for choosing the Battlement Mesa site for the new community can be summarized as follows:

Most workers will prefer to live as close to their jobs as possible. This site locates a majority of Colony's workers near Parachute and would place them in the same school district and fire district as the oil shale plant, which will assure that tax revenues from the industrial plant will be available to such districts. This location would also reduce worker commuting and be beneficial in energy conservation and vehicular air pollution reduction. Strip development would also be minimized. The new community concept would greatly reduce the impact on Parachute and other communities.

The primary purpose of developing Battlement Mesa as a new community is to provide housing for construction and operational personnel working on Colony, and it should be emphasized, on other potential oil shale projects located north of Parachute, Colorado. Such residential development and related public and business services will benefit the region in the following ways:

a. The existing cities and towns in Garfield County will not be damaged by rapid population increases beyond their ability to provide housing and necessary public services.

b. Scattering of housing and business services in an undesirable manner in unincorporated areas, especially along the Colorado River Valley, can be minimized.

c. Unnecessarily long travel distances from workers' places of employment to housing areas will be avoided, thus reducing travel costs, added traffic hazards, and increased air pollution.

d. Employees in the oil shale industry will have an added variety of housing choices and convenience of location which should improve their morale and satisfaction with the area as a place of employment.

Enhanced Oil Recovery Development Option

Enhanced Oil Recovery as proposed in Kern County, California would utilize existing oil recovery facilities thereby reducing considerably the impacts of development. The peak construction employment is estimated at 600 workers. Operation employment is estimated at 175 and would generate service employment of approximately 260 workers. The resulting population induced by the project would number about 1,000 and would represent a minor effect on baseline county population characteristics.

Retail expenditures by the new population would generate approximately $53,000 in sales taxes annually. Property taxes generated by the new population would amount to approximately $75,000 annually and state income tax would be approximately $370,000 each year.

The capital value of the EOR facilities has been estimated at about $380 million and would generate property tax revenues of approximately $2.9 million annually.

Total revenues generated by the EOR development would be over $3.3 million annually. Public costs associated with the new population would total about $1.4 million, significantly less than project related costs.

Outer Continental Shelf Development Option

Outer Continental Shelf development would also utilize existing systems requiring the smallest construction and operation work force of all the alternatives. This development option is estimated to require only 120 construction workers and 44 operation personnel, 30 offshore and 14 onshore. Operation employment would generate an additional 66 service employees resulting in a total population increment of 254 which would be insignificant in the proposed areas of Santa Barbara, California or the Gulf Coast in Texas.

Residential property taxes would amount to about $19,000 annually. Income taxes paid to the state by project related employees would amount to less than $940,000 annually. Sales taxes would amount to only $13,000 per year.

Total revenues would amount to about $3.5 million per year, the largest share of which would come from property taxes on the OCS facilities. Public service costs for the project related population would be quite low due to the small number of people involved. Only about $350,000 would likely be expended by local service agencies.

Biomass/Alcohol Development Option

Alcohol production would not be new to central Illinois; however, the project would require total operation work force several times larger than the EOR and OCS alternatives and intensive development would be required to ensure rapid attainment of a 200,000 BPD equivalent. The construction force of fourteen 3,600-BPD plants would require almost 2,000 employees during peak construction activity. The total operation work force would also be relatively large (approximately 2,200). Operation employment would generate an additional 3,300 service workers resulting in a project-related population increment of almost 12,600 people throughout the affected areas. Since it is likely that the 14 plants will not be located in a single site, the population increase in any one community would be only a fraction of the total population increase. In some agricultural communities an increase in employment opportunities would have a beneficial effect.

The induced population would generate almost $65 million in property taxes annually and over $1 million in sales taxes. Income taxes would total over $4.5 million per year.

The capital value of gasohol facilities is less than any of the other alternatives and would account for relatively smaller property tax revenues to local jurisdictions. The facilities are estimated to have a capital value of about $812 million and would generate property taxes of approximately $6.1 million annually.

As a result, public revenues from gasohol development would total about $13.2 million. Public service costs would total about $27 million dollars representing a potential deficit of almost $13 million per year to state and local governments.

Coal Liquefaction Development Option

Coal liquefaction is the most labor intensive alternative. Peak construction employment has been estimated at 7,089 workers which is far in excess of the other development options. The operation work force has been estimated to be 1,774 workers. Service employment generated by the operation activity would total almost 6,000. The resulting population increment of over 20,000 persons would significantly impact the socioeconomic environment of Morgantown, West Virginia.

The induced population would generate over $1.7 million in annual residential property taxes. Project related employment would generate approximately $8.5 million in state income taxes and almost $1.5 million in sales taxes each year.

Property taxes on the coal liquefaction facility would amount to almost $18 million annually. The total revenues generated by the project would then total nearly $30 million annually.

Public service costs, however, would be overwhelming. Local government capital expenditures would likely be more than $18 million per year. The cost of expanding human services delivery would be almost $14 million per year representing a total annual public service cost of over $32 million. It is clearly infeasible that project generated revenues could offset the public service costs and social impact of this alternative.

Conservation Option

The conservation alternative is difficult to assess in socioeconomic terms. The primary consequence of saving 50,000 BPD of gasoline is a 0.6% decrease in the amount of gasoline pumped across the nation. This does not sound high enough to affect the service station industry, but might conceivably impact the gasoline distribution industry slightly. The socioeconomic impacts of the conservation alternative as defined are expected to be minor since vehicle design changes would probably be accommodated in annual model changes routine to the auto industry, which do not generate any significant demand for new employment. As mentioned in Section 3.10, no socioeconomic analysis of this alternative has been attempted here.

Comparative Socioeconomic Analysis Data Summary

A summary of employment, capital cost, revenue, and public cost data for the socioeconomic comparisons of the technology alternatives and development policy options is presented in Table 5-13.

5.2.3 Cumulative Socioeconomic Effects of NOSR Development in Western Colorado

In the preceding comparative analysis, NOSR 1 impacts were considered in isolation. However, the magnitude of the cumulative socioeconomic impacts that could be manifested in the three county regions of interest in Colorado, are of special interest since they could exercise great influence on the timing and configuration of the ultimate development policy adopted with regard to NOSR 1.

In order to examine the issue, a cumulative socioeconomic impact analysis was performed. The analysis recognizes the possible development of various oil shale, synthetic fuels, and coal mining projects in western Colorado over the next 20 years, and portrays the population and fiscal implications that these combined developments will have with and without a 100,000 BPD NOSR development. The specific energy developments that have been modeled include: the Colony, Union, C-b, and Mobil oil shale projects; the GEX, Sheridan, Snowmass, Colowyo, Northern coal projects; new coal leasing under the Hams Fork/Green River Program; and the Moon Lake Power Project.

Table 5-13. Comparative Socioeconomic Analysis Data Summary

		50,000 BPD NOSR (INDUSTRY)	50,000 BPD NOSR (GOCO)	200,000 BPD NOSR (INDUSTRY)	200,000 BPD NOSR (GOCO)	ENHANCED OIL RECOVERY	COAL LIQUE-FACTION	50,00 BPD OUTER CONTINENTAL SHELF	GASOHOL (BIOMASS ALCOHOL)	COLONY
1.	Peak Construction Employment	2,100	2,100	2,100	2,100	600	7,089	120	2,000	2,400
2.	Peak Operation Employment	1,200	1,200	4,000	4,000	175	1,774	30	2,200	1,200
3.	Operation Induced Employment	1,800	1,800	6,000	6,000	263	6,000	45	3,300	1,800
4.	Population Associated with Operation and Induced Employment	7,500	7,500	23,000	23,000	1,000	23,000	173	12,600	7,000
5.	Capital Value of Facility ($000)	$1,295,000	$875,000*	$4,700,000	$3,200,000*	$360,000	$2,400,000	$375,000	$812,000	$1,270,000
6.	Estimated Annual Property Tax Revenue from Facility ($000)	$9,713	**	$35,500	**	$2,650	$18,000	$2,812	$6,090	$9,525
7.	Average Annual Residential Property Tax Revenue ($000)	$562	$562	$1,725	$1,725	$76	$1,725	$12,975	$1,449	$5,175
8.	Average Annual Sales Tax Revenues ($000)	$371.5	$371.5	$1,486	$1,486	$53.5	$1,486	$9	$1,026	$367
	Direct Operational	$210	$210	$700	$700	$30.6	$700	$5	$588	$210
	Induced Employment	$236	$236	$786	$786	$23	$786	$4	$440	$157
9.	Average Annual State Income Tax Revenue ($000)	$2,550	$2,550	$8,500	$8,500	$372	$8,550	$637.5	$4,675	$2,550
	Direct Operational	$1,200	$1,200	$4,000	$4,000	$175	$4,000	$30	$2,200	$1,200
	Induced Employment	$1,350	$1,350	$4,500	$4,500	$197	$4,500	$34	$2,475	$1,350
10.	Total Average Annual Revenues ($000)	$13,190	$3,550	$47,200	$11,711	$3,351	$29,711	$3,472	$13,242	$12,959
11.	Total Average Annual Public Costs ($000)	$10,500	$10,500	$32,200	$32,200	$1,411	$32,200	$242	$27,000	$9,660
	Capital Costs	$6,000	$6,000	$18,400	$18,400	$806	$18,400	$138	$15,450	$5,520
	Service Costs	$4,500	$4,500	$13,800	$13,800	$605	$13,800	$104	$11,550	$4,140

* Government ownership cost does not include land cost, insurance and contingency funds.
**Property taxes lost to local government with loss offset only partially by PILT.

Figure 5-1 and Tables 5-14 and 5-15 illustrate the combined population effect of these developments juxtaposed with a 100,000 BPD development at NOSR 1. The production level at NOSR 1 is assumed to be realized through two 50,000 BPD mining and surface retort facilities with the first plant introduced in 1987 and a second in 1989. Four communities would experience substantial growth in the three county region (Parachute, Rifle, Battlement Mesa, and Meeker) and under the assumed development scenario the additive impact of the NOSR development can be seen in Figures 5-2 through 5-5 and Tables 5-16 through 5-23.

It should be emphasized that the population growth reflected in the previous Tables and Figures is modeled on the basis of a hypothetical energy development scenario in western Colorado and a hypothetical development option at NOSR 1. No specific policy option is thus implied.

The population growth that will be attendant to the combined or cumulative energy development in western Colorado and the growth associated with development at NOSR 1 will have obvious fiscal implications for local governments in the region. A comprehensive analysis of public costs that could be associated with the hypothetical cumulative development scenario presented above is summarized in Tables 5-24 and 5-25 below. Most of the public costs associated with energy development are due to the increase in demand for facilities and services by the new population which accompanies the capital intensive/labor intensive energy facility. The number of people and the rate of in-migration affects the level of expenditures that must be made to meet the new demand.

The typical oil shale corridor community in Colorado has existed for years with a very modest municipal budget, issuing revenue bonds occasionally to cover costs of upgrading the water and sewer systems, and avoiding issuing general obligation bonds except, on occasion, to upgrade school facilities. Access to adequate housing, schools, and recreation facilities is considered to be a prime factor in attracting a productive, stable, skilled work force, but the costs of upgrading existing facilities and providing new facilities and services could be overwhelming when compared to the current budgets of counties and municipalities in western Colorado.

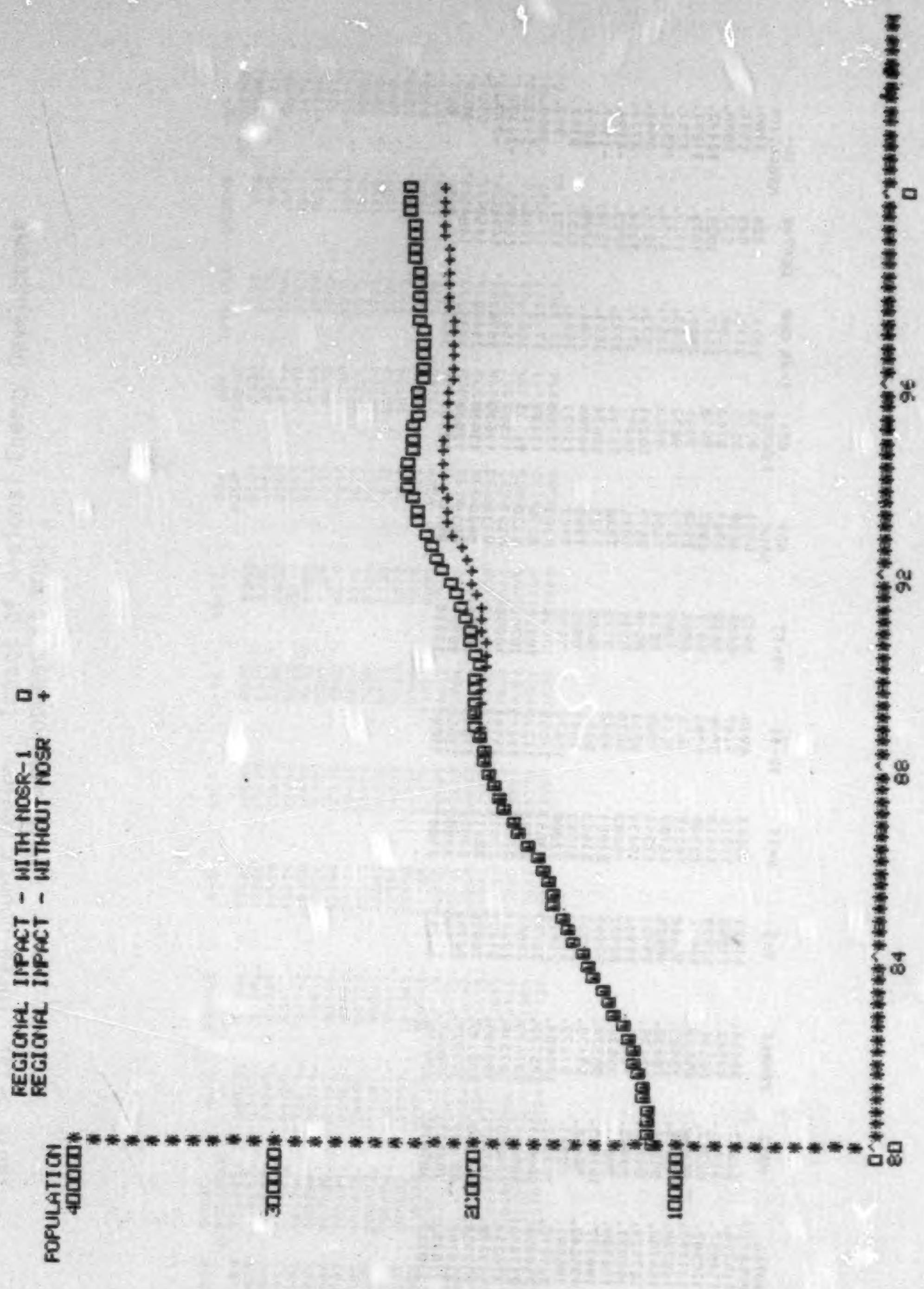

Figure 5-1. Three-County Region

Table 5-14. Three-County Region Regional Energy Impact - Without NOSR

YEAR	TOTAL POPULATION	MALE	FEMALE	0-5	6-11	12-14	15-17	60+ MALE	60+ FEMALE	1-YR OLD	DEATHS	IN-MIGRATION
1980	110295.	54831.	55464.	11225	10643	4970	5942	6561	8335	2072.	926.	3186.
1981	114657.	57115.	57542.	11960	11014	5147	5685	6650	8528	2172.	949.	4691.
1982	120582.	60248.	60334.	12928	11428	5496	5632	6761	8743	2288.	977.	9888.
1983	131791.	66258.	65533.	14616	12340	6294	5877	6937	9018	2517.	1021.	12472.
1984	145758.	73575.	72183.	16408	14032	7075	6586	7155	9344	2800.	1073.	11291.
1985	158780.	80344.	78436.	18020	15787	7606	7309	7371	9670	3063.	1123.	7201.
1986	167920.	84742.	83179.	19194	17316	7868	8078	7409	9868	3251.	1154.	15024.
1987	185031.	93965.	91066.	21144	19471	8534	8916	7673	10221	3573.	1216.	6942.
1988	194209.	98573.	95636.	22117	20882	9020	9215	7825	10497	3717.	1254.	2724.
1989	199377.	101053.	98324.	22485	21851	9348	9172	7918	10718	3772.	1282.	-6194.
1990	195642.	98466.	97176.	21837	21543	9496	8080	7725	10674	3651.	1272.	-1397.
1991	196582.	98911.	97672.	21547	21562	9847	8883	7788	10798	3584.	1288.	4099.
1992	202916.	102312.	100604.	21872	22088	10474	9216	7957	11021	3611.	1323.	9107.
1993	214253.	108531.	105722.	22797	23053	11055	10005	820[illegible]	11286	37[illegible]7.	1373.	902.
1994	217484.	109861.	107623.	22865	23283	11318	10522	8278	11424	3713.	1375.	-3600.
1995	216214.	108895.	107319.	22261	22944	11313	10761	8320	11503	3567.	1405.	-5155.
1996	213278.	107087.	106191.	21491	22414	11141	10698	8321	11527	3543.	1409.	-2433.
1997	212954.	106837.	106117.	20996	22111	11050	10747	8432	11639	3478.	1425.	-277.
1998	214704.	107677.	107026.	20752	21971	11039	10894	8620	11846	3449.	1452.	65.
1999	216751.	108667.	108084.	20590	21805	11056	10981	8838	12082	3435.	1481.	31.
2000	218727.	109619.	109108.	20455	21601	11061	11019	9071	12341	3427.	0.	0.

Table 5-15. Three-County Region - Impact of Regional Energy Development with Development at NOSR 1

YEAR	TOTAL POPULATION	MALE	FEMALE	0-5	6-11	12-14	15-17	60+ MALE	60+ FEMALE	1-YR OLD	DEATHS	IN-MIGRATION
1980	110295.	54831.	55464.	11225	10643	4970	5942	6561	8335	2072.	926.	3186.
1981	114657.	57115.	57542.	11960	11014	5147	5685	6650	8528	2172.	949.	4691.
1982	120582.	60248.	60334.	12928	11428	5496	5632	6761	8743	2280.	977.	9888.
1983	131791.	66258.	65533.	14616	12340	6294	5877	6937	9018	2517.	1021.	12472.
1984	145758.	73575.	72183.	16408	14032	7075	6586	7155	9344	2800.	1073.	11291.
1985	158780.	80344.	78436.	18020	15787	7606	7309	7371	9670	3063.	1123.	7201.
1986	167920.	84742.	83179.	19194	17316	7868	8078	7409	9868	3251.	1154.	15024.
1987	185031.	93965.	91066.	21144	19471	8534	8916	7673	10221	3573.	1216.	7059.
1988	194426.	98699.	95727.	22140	20904	9029	9224	7834	10502	3721.	1255.	3950.
1989	200823.	101887.	98935.	22641	22000	9411	9236	7972	10752	3798.	1288.	-4808.
1990	198494.	100087.	98407.	22151	21845	9629	9013	7821	10759	3702.	1285.	4212.
1991	205082.	103737.	101345.	22508	22402	10196	9235	7985	10975	3747.	1320.	8868.
1992	216314.	109770.	106544.	23485	23473	11078	9827	8224	11266	3879.	1369.	10105.
1993	228872.	116424.	112448.	24605	24691	11802	10727	8500	11586	4048.	1424.	4202.
1994	235663.	119643.	116020.	25086	25370	12264	11414	8656	11808	4133.	1459.	-7026.
1995	231287.	116645.	114642.	24254	24807	12124	11541	8536	11778	4014.	1453.	-5392.
1996	22842[illegible].	114865.	113555.	23471	24307	11940	11478	8553	11818	3894.	1458.	-2412.
1997	228421.	114777.	113645.	22993	24044	11869	11544	8682	11957	3827.	1477.	-191.
1998	230550.	115804.	114746.	22775	23937	11887	11699	8899	12189	3794.	1506.	104.
1999	232923.	116955.	115968.	22627	23771	11963	11788	9132	12451	3777.	1539.	34.
2000	235181.	118044.	117137.	22489	23557	12026	11843	9384	12734	3764.	0.	0.

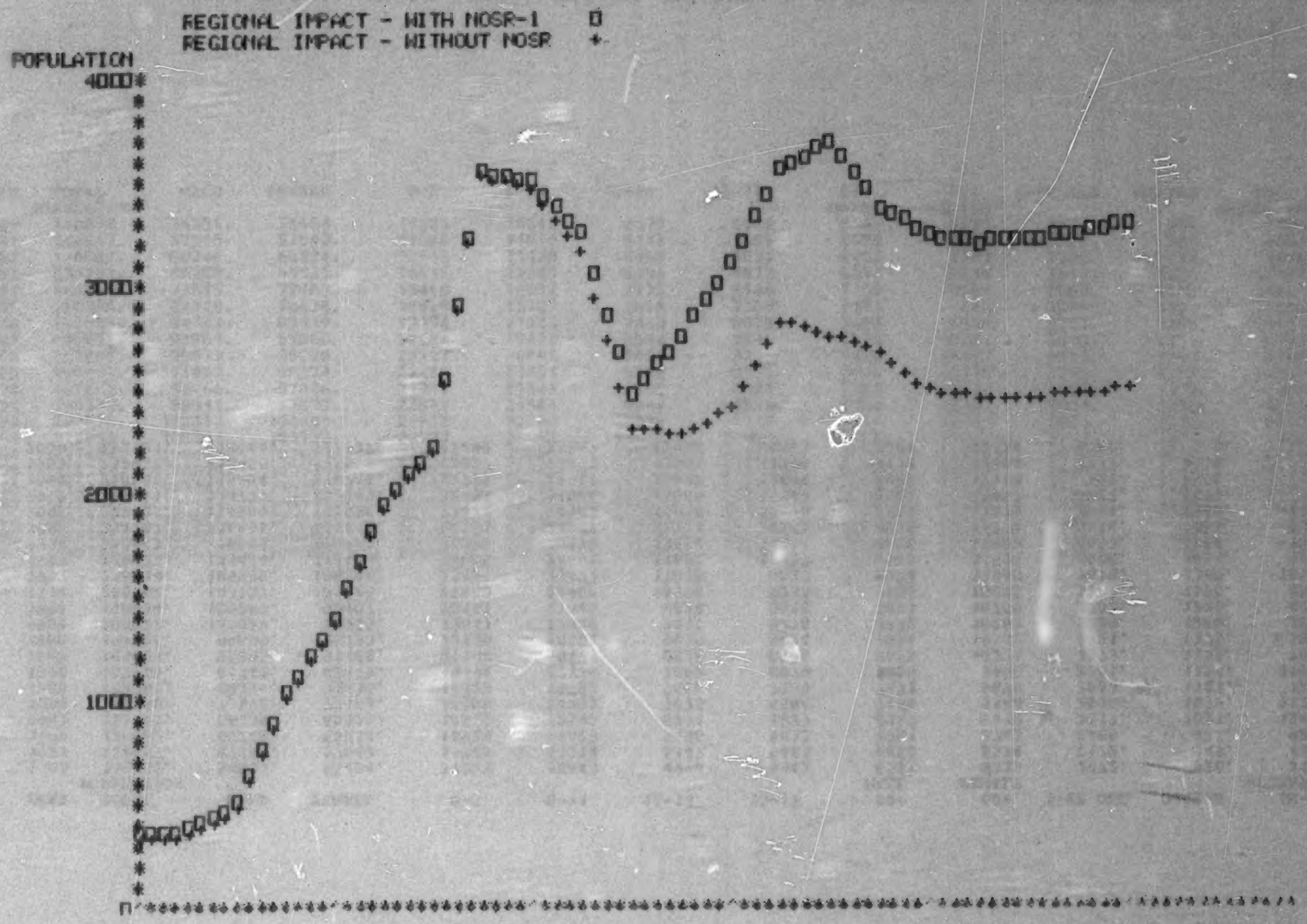

Figure 5-2. Parachute, Colorado

Table 5-16. Regional Energy Impact - Without NOSR

Parachute, Colorado

YEAR	TOTAL POPULATION	MALE	FEMALE	0-5	6-11	12-14	15-17	60+ MALE	60+ FEMALE	1-YR OLD	DEATHS	IN-MIGRATION
1980	339.	173.	166.	32	38	15	20	36	41	5.	5.	25.
1981	365.	188.	177.	35	42	20	20	33	42	6.	5.	122.
1982	488.	257.	231.	48	53	27	23	34	42	9.	5.	526.
1983	1018.	559.	459.	116	101	49	46	37	44	20.	7.	344.
1984	1376.	739.	637.	169	147	70	69	40	49	29.	7.	537.
1985	1934.	1043.	891.	239	211	92	97	46	54	41.	9.	237.
1986	2204.	1170.	1034.	279	248	111	113	48	59	48.	10.	1270.
1987	3521.	1936.	1585.	433	373	158	160	66	70	75.	14.	-121.
1988	3460.	1884.	1576.	430	373	164	154	67	71	73.	13.	-380.
1989	3138.	1684.	1454.	390	351	153	140	65	72	65.	12.	-891.
1990	2299.	1182.	1117.	296	275	120	109	48	60	49.	10.	-57.
1991	2280.	1178.	1102.	284	270	119	110	51	62	46.	10.	78.
1992	2393.	1249.	1144.	289	280	124	113	55	62	47.	10.	383.
1993	2812.	1494.	1318.	331	318	140	131	63	68	54.	11.	-118.
1994	2735.	1434.	1301.	321	315	140	132	63	70	52.	11.	-124.
1995	2651.	1372.	1278.	305	307	142	131	61	72	50.	11.	-226.
1996	2463.	1257.	1205.	280	291	136	123	60	73	46.	11.	-65.
1997	2432.	1238.	1194.	270	284	136	123	62	74	44.	11.	-34.
1998	2430.	1236.	1194.	260	282	135	127	66	77	43.	11.	-14.
1999	2447.	1244.	1203.	256	270	136	129	68	81	42.	11.	-2.
2000	2475.	1257.	1218.	252	276	137	132	72	85	42.	0.	0.

Table 5-17. Impact of Regional Energy Development

Parachute, Colorado

YEAR	TOTAL POPULATION	MALE	FEMALE	0-5	6-11	12-14	15-17	60+ MALE	60+ FEMALE	1-YR OLD	DEATHS	IN-MIGRATION
1980	339.	173.	166.	32	38	15	20	36	41	5.	5.	25.
1981	365.	188.	177.	35	42	20	20	33	42	6.	5.	122.
1982	488.	257.	231.	48	53	27	23	34	42	9.	5.	526.
1983	1018.	559.	459.	116	101	49	46	37	44	20.	7.	344.
1984	1376.	739.	637.	169	147	70	69	40	49	29.	7.	537.
1985	1934.	1043.	891.	239	211	92	97	46	54	41.	9.	237.
1986	2204.	1170.	1034.	279	248	111	113	48	59	48.	10.	1278.
1987	3521.	1936.	1585.	433	373	158	160	66	70	75.	14.	-110.
1988	3471.	1890.	1581.	431	373	164	154	68	71	73.	13.	-312.
1989	3218.	1731.	1487.	399	357	156	143	67	72	67.	13.	-827.
1990	2444.	1267.	1177.	310	290	126	114	52	62	51.	10.	251.
1991	2735.	1444.	1291.	336	314	135	127	59	66	55.	11.	285.
1992	3063.	1633.	1430.	367	344	150	140	66	73	60.	12.	412.
1993	3521.	1884.	1636.	415	395	174	163	76	79	67.	14.	71.
1994	3644.	1931.	1713.	427	418	186	173	81	86	69.	14.	-362.
1995	3337.	1725.	1611.	396	393	180	166	74	86	65.	13.	-192.
1996	3196.	1634.	1562.	373	380	176	162	74	87	62.	13.	-82.
1997	3161.	1613.	1548.	360	376	175	161	74	90	59.	13.	-29.
1998	3178.	1620.	1558.	352	374	175	165	82	93	58.	14.	-12.
1999	3210.	1635.	1575.	347	373	178	170	86	98	57.	14.	-2.
2000	3250.	1654.	1596.	343	368	182	173	89	103	57.	0.	0.

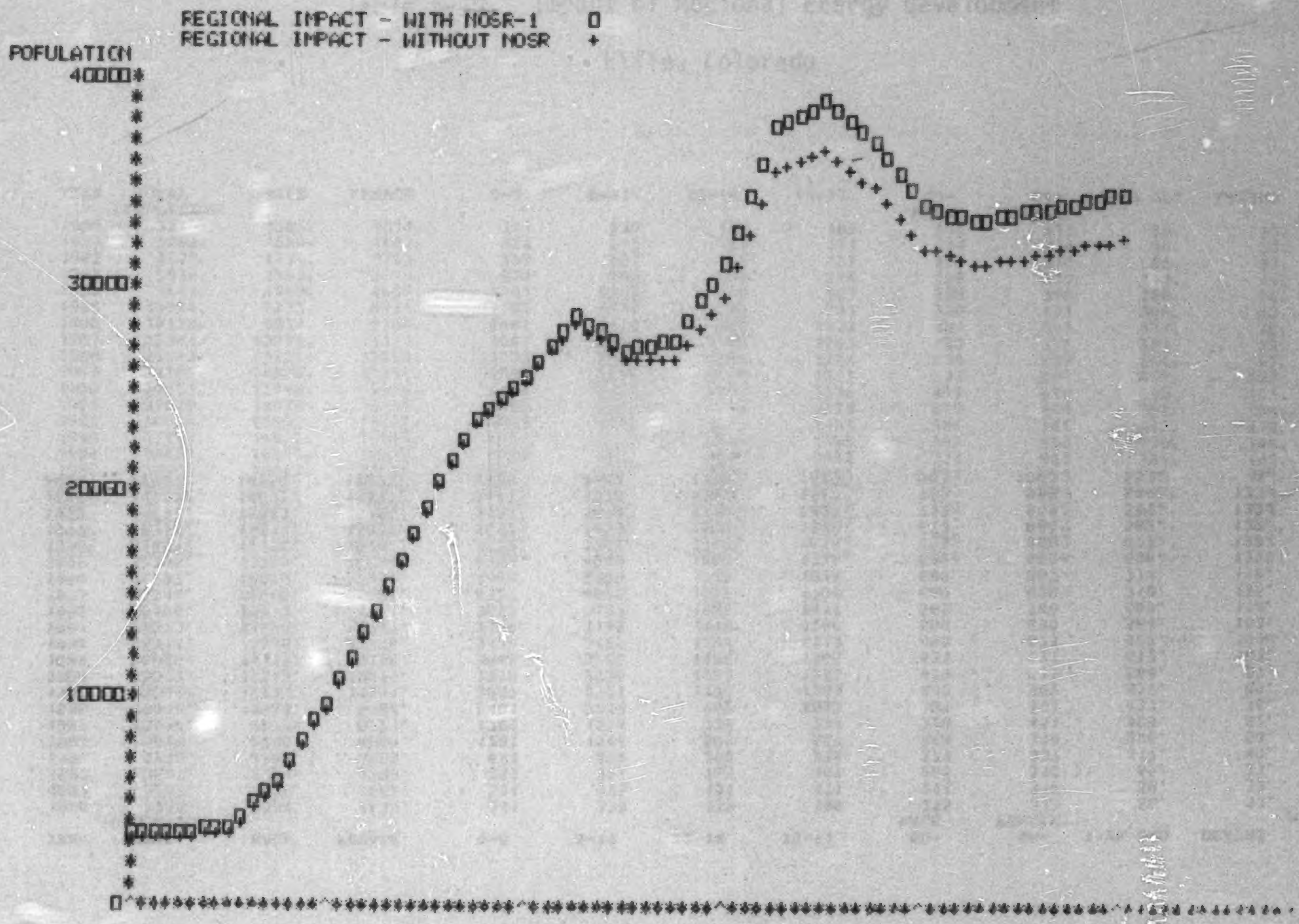

Figure 5-3. Rifle, Colorado

Table 5-18. Regional Energy Impact - Without NOSR

Rifle, Colorado

YEAR	TOTAL POPULATION	MALE	FEMALE	0-5	6-11	12-14	15-17	60+ MALE	60+ FEMALE	1-YR OLD	DEATHS	IN-MIGRATION
1980	3215.	1584.	1631.	311	330	139	185	215	313	56.	33.	42.
1981	3282.	1620.	1662.	324	335	151	171	214	314	58.	33.	219.
1982	3527.	1734.	1793.	369	361	165	167	205	310	65.	33.	2257.
1983	5818.	2983.	2835.	674	592	290	275	229	337	117.	40.	3721.
1984	9619.	4960.	4659.	1201	1044	509	507	268	390	206.	50.	4212.
1985	13994.	7273.	6721.	1782	1574	728	731	320	451	309.	62.	[illegible]
1986	19118.	9934.	9184.	2481	2214	992	1622	381	531	431.	76.	3851.
1987	23344.	12233.	11111.	3007	2701	1170	1203	440	592	527.	89.	1541.
1988	25327.	13312.	12015.	3238	2936	1263	1252	479	635	564.	97.	2262.
1989	28055.	14755.	13299.	3566	3266	1408	1365	531	691	613.	107.	-2245.
1990	26314.	13538.	12776.	3424	3165	1391	1312	490	673	582.	101.	-516.
1991	26273.	13526.	12747.	3359	3145	1419	1290	508	690	564.	103.	2469.
1992	29196.	15173.	14023.	3652	3427	1560	1417	565	740	609.	114.	5663.
1993	35344.	18660.	16684.	4327	4025	1818	1700	669	828	718.	135.	381.
1994	36297.	18938.	17359.	4466	4209	1917	1825	689	867	734.	138.	-2491.
1995	34395.	17760.	16634.	4169	4043	1863	1738	682	870	686.	135.	-3324.
1996	31609.	16128.	15482.	3772	3765	1747	1616	653	856	617.	128.	-1334.
1997	30755.	15677.	15077.	3562	3653	1697	1586	673	866	582.	128.	-101.
1998	31098.	15843.	15256.	3497	3674	1710	1627	713	909	571.	132.	0.
1999	31530.	16052.	15477.	3447	3678	1742	1665	759	959	564.	137.	0.
2000	31949.	16256.	15693.	3398	3662	1778	1689	803	1005	557.	0.	0.

Table 5-19. Impact of Regional Energy Development

Rifle, Colorado

YEAR	TOTAL POPULATION	MALE	FEMALE	0-5	6-11	12-14	15-17	60+ MALE	60+ FEMALE	1-YR OLD	DEATHS	IN-MIGRATION
1980	3215.	1584.	1631.	311	330	139	185	219	313	56.	33.	42.
1981	3282.	1620.	1662.	324	335	151	171	214	314	58.	33.	219.
1982	3527.	1734.	1793.	369	361	165	167	205	310	65.	33.	2257.
1983	5818.	2983.	2835.	674	592	290	275	229	337	117.	40.	3721.
1984	9619.	4960.	4659.	1201	1044	509	507	268	390	206.	50.	4212.
1985	13994.	7273.	6721.	1782	1574	728	731	320	451	309.	62.	4868.
1986	19118.	9934.	9184.	2481	2214	992	1022	381	531	431.	76.	3861.
1987	23344.	12233.	11111.	3007	2701	1170	1203	440	592	527.	89.	1558.
1988	25343.	13322.	12022.	3230	2936	1265	1254	480	635	564.	97.	2372.
1989	28180.	14826.	13354.	3582	3279	1414	1371	533	691	616.	107.	-2065.
1990	26623.	13708.	12914.	3464	3198	1406	1326	495	678	589.	102.	-24.
1991	27079.	13974.	13105.	3459	3229	1454	1325	519	699	582.	106.	3178.
1992	30725.	16002.	14723.	3847	3597	1634	1493	586	765	642.	118.	5938.
1993	37178.	19632.	17545.	4567	4242	1915	1795	693	856	759.	140.	623.
1994	38409.	20057.	18352.	4739	4461	2030	1932	721	903	781.	145.	-2533.
1995	36505.	18849.	17656.	4453	4307	1978	1850	711	908	735.	141.	-3616.
1996	33471.	17087.	16384.	4019	4001	1847	1715	681	888	660.	134.	-1261.
1997	32725.	16691.	16034.	3818	3902	1805	1689	702	905	625.	134.	-82.
1998	33125.	16885.	16241.	3756	3926	1823	1732	747	952	615.	139.	0.
1999	33593.	17112.	16481.	3706	3933	1860	1771	795	1003	607.	145.	0.
2000	34048.	17333.	16715.	3656	3917	1901	1797	846	1054	599.	0.	0.

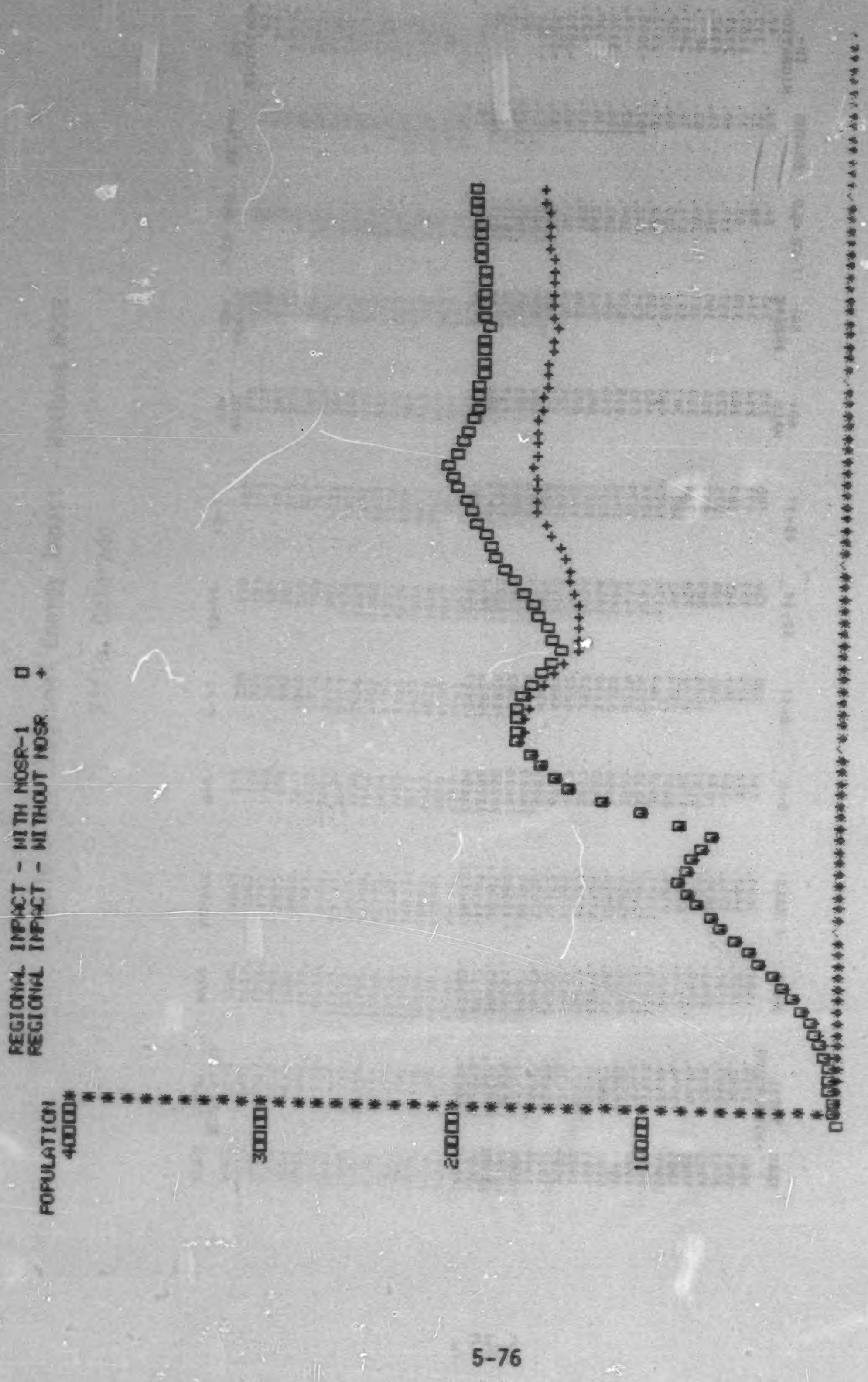

Figure 5-4. Battlement Mesa, Colorado

Table 5-20. Regional Energy Impact - Without NOSR

Battlement Mesa, Colorado

YEAR	TOTAL POPULATION	MALE	FEMALE	0-5	6-11	12-14	15-17	60+ MALE	60+ FEMALE	1-YR OLD	DEATHS	IN-MIGRATION
1980	0.	0.	0.	0	0	0	0	0	0	0.	0.	287.
1981	287.	169.	118.	34	24	9	12	2	0	6.	1.	1041.
1982	1333.	771.	562.	163	126	49	55	17	11	28.	4.	1865.
1983	3222.	1852.	1370.	393	308	124	132	41	29	67.	10.	2675.
1984	5953.	3381.	2572.	735	590	246	252	79	59	124.	18.	2256.
1985	8315.	4680.	3635.	1030	851	361	353	118	96	173.	25.	-2007.
1986	6457.	3443.	3014.	859	744	324	315	89	87	144.	19.	7497.
1987	14079.	7611.	6469.	1833	1594	676	701	181	182	310.	40.	2379.
1988	16735.	8921.	7813.	2207	1955	842	844	223	239	376.	48.	-876.
1989	16191.	8533.	7658.	2134	1952	839	801	229	250	367.	48.	-2651.
1990	13856.	7167.	6690.	1842	1736	745	684	205	238	314.	42.	-375.
1991	13748.	7101.	6646.	1790	1733	740	682	219	252	300.	43.	517.
1992	14518.	7506.	7011.	1851	1814	795	731	246	282	308.	47.	1133.
1993	15908.	8248.	7660.	1992	1951	888	810	281	318	329.	53.	-38.
1994	16143.	8342.	7800.	1983	1970	923	824	300	343	326.	55.	-486.
1995	15922.	8204.	7719.	1905	1927	927	826	315	359	313.	57.	-648.
1996	15525.	7974.	7551.	1807	1865	905	831	322	370	296.	57.	-636.
1997	15122.	7732.	7390.	1717	1798	884	830	331	380	280.	58.	-70.
1998	15269.	7801.	7469.	1683	1788	880	854	353	403	274.	61.	0.
1999	15480.	7902.	7578.	1659	1783	882	867	373	428	272.	64.	0.
2000	15687.	8001.	7686.	1637	1768	887	878	396	451	270.	0.	0.

Table 5-21. Impact of Regional Energy Development

Battlement Mesa, Colorado

YEAR	TOTAL POPULATION	MALE	FEMALE	0-5	6-11	12-14	15-17	60+ MALE	60+ FEMALE	1-YR OLD	DEATHS	IN-MIGRATION
1980	0.	0.	0.	0	0	0	0	0	0	0.	0.	287.
1981	287.	169.	118.	34	24	9	12	2	0	6.	1.	1041.
1982	1333.	771.	562.	163	126	49	55	17	11	28.	4.	1065.
1983	3222.	1852.	1370.	393	308	124	132	41	29	67.	10.	2675.
1984	5953.	3381.	2572.	735	590	246	252	79	59	124.	18.	2256.
1985	8315.	4680.	3635.	1030	851	361	353	118	96	173.	25.	-2007.
1986	6457.	3443.	3014.	859	744	324	315	89	87	144.	19.	7497.
1987	14079.	7611.	6469.	1833	1594	676	701	181	182	310.	40.	2443.
1988	16799.	8958.	7841.	2214	1962	845	847	223	239	377.	48.	-540.
1989	16592.	8762.	7830.	2181	1994	857	818	237	254	375.	49.	-2317.
1990	14599.	7588.	7011.	1926	1815	779	716	218	248	329.	44.	1137.
1991	16015.	8386.	7629.	2060	1967	835	779	254	283	347.	50.	1601.
1992	17908.	9396.	8512.	2269	2171	947	886	296	326	378.	57.	1097.
1993	19323.	10102.	9221.	2426	2333	1059	973	334	370	402.	63.	775.
1994	20434.	10661.	9772.	2520	2462	1144	1029	368	412	417.	69.	-1620.
1995	19159.	9871.	9288.	2338	2329	1103	988	362	415	387.	66.	-646.
1996	18827.	9674.	9153.	2239	2278	1083	999	378	430	368.	68.	-649.
1997	18572.	9506.	9066.	2155	2232	1070	1011	392	448	353.	69.	-63.
1998	18788.	9609.	9179.	2122	2229	1072	1036	417	479	347.	73.	0.
1999	19058.	9739.	9319.	2095	2225	1085	1050	444	506	343.	76.	0.
2000	19322.	9865.	9457.	2065	2210	1102	1063	471	539	340.	0.	0.

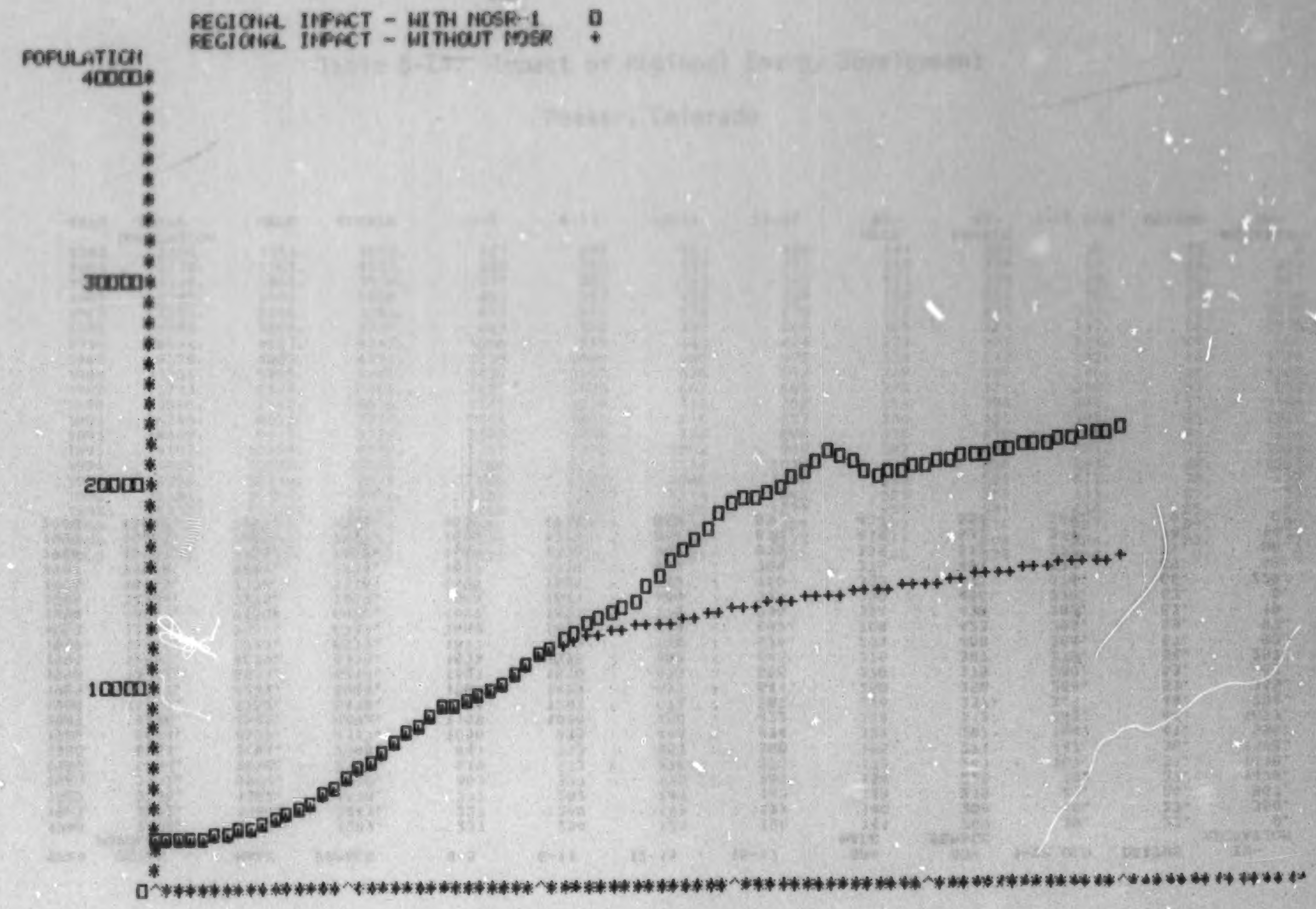

Figure 5-5. Meeker, Colorado

Table 5-22. Regional Energy Impact - Without NOSR

Meeker, Colorado

YEAR	TOTAL POPULATION	MALE	FEMALE	0-5	6-11	12-14	15-17	60+ MALE	60+ FEMALE	1-YR OLD	DEATHS	IN-MIGRATION
1980	2356.	1153.	1202.	227	254	121	126	141	209	39.	23.	0.
1981	2372.	1161.	1211.	227	260	113	122	140	208	40.	23.	350.
1982	2740.	1362.	1378.	277	282	141	143	143	215	48.	24.	967.
1983	3732.	1904.	1828.	403	397	178	189	154	225	70.	27.	1478.
1984	5254.	2690.	2565.	619	572	276	270	172	247	107.	31.	1619.
1985	6953.	3604.	3349.	841	753	357	360	195	271	147.	36.	1578.
1986	8644.	4527.	4117.	1056	939	443	424	221	297	184.	41.	586.
1987	9376.	4885.	4492.	1159	1040	480	472	234	312	202.	44.	1627.
1988	11163.	5752.	5410.	1424	1292	572	587	246	337	245.	48.	794.
1989	12157.	6232.	5925.	1561	1429	637	641	258	358	269.	51.	355.
1990	12732.	6513.	6219.	1627	1510	673	656	270	375	280.	53.	-62.
1991	12897.	6579.	6318.	1632	1539	689	645	278	387	279.	54.	297.
1992	13416.	6843.	6573.	1677	1603	718	676	293	408	284.	57.	92.
1993	13732.	7001.	6731.	1688	1634	744	692	308	423	283.	59.	97.
1994	14049.	7159.	6890.	1697	1657	775	716	324	438	282.	61.	19.
1995	14284.	7276.	7009.	1688	1671	800	727	339	456	278.	63.	0.
1996	14495.	7378.	7116.	1670	1683	812	750	358	472	274.	66.	220.
1997	14918.	7591.	7326.	1677	1719	831	789	375	491	274.	69.	68.
1998	15187.	7725.	7462.	1664	1732	842	815	395	512	272.	71.	68.
1999	15453.	7856.	7597.	1652	1739	854	830	415	532	271.	74.	14.
2000	15662.	7957.	7704.	1632	1736	859	837	434	554	269.	0.	0.

Table 5-23. Impact of Regional Energy Development

Meeker, Colorado

YEAR	TOTAL POPULATION	MALE	FEMALE	0-5	6-11	12-14	15-17	60+ MALE	60+ FEMALE	1-YR OLD	DEATHS	IN-MIGRATIO
1980	2356.	1153.	1202.	227	254	121	126	141	209	39.	23.	0
1981	2372.	1161.	1211.	227	260	113	122	140	208	40.	23.	350
1982	2740.	1362.	1378.	277	282	141	143	143	215	48.	24.	967.
1983	3732.	1904.	1828.	403	397	178	189	154	225	70.	27.	1478.
1984	5254.	2690.	2565.	619	572	276	270	172	247	107.	31.	1619.
1985	6953.	3604.	3349.	841	753	357	360	195	271	147.	36.	1578.
1986	8644.	4527.	4117.	1056	939	443	424	221	297	184.	41.	586.
1987	9376.	4885.	4492.	1159	1040	480	472	234	312	202.	44.	1716.
1988	11251.	5805.	5446.	1430	1301	576	590	249	338	246.	48.	1280.
1989	12733.	6574.	6160.	1621	1483	661	665	273	371	230.	53.	855.
1990	13816.	7147.	6670.	1747	1614	716	702	294	394	301.	57.	2186.
1991	16245.	8533.	7712.	2018	1851	816	777	334	431	346.	65.	1926.
1992	18449.	9717.	8732.	2283	2090	926	889	376	470	385.	73.	438.
1993	19197.	10004.	9194.	2391	2222	1002	949	387	492	401.	75.	1523.
1994	21043.	10978.	10065.	2588	2435	1114	1039	426	538	433.	82.	-1595.
1995	19796.	10118.	9678.	2466	2355	1086	1009	399	526	412.	78.	227.
1996	20352.	10397.	9955.	2481	2426	1114	1042	425	556	413.	82.	53.
1997	20732.	10585.	10147.	2468	2470	1130	1073	455	581	410.	85.	92.
1998	21143.	10789.	10354.	2460	2507	1154	1105	482	614	407.	89.	99.
1999	21555.	10992.	10563.	2449	2526	1189	1125	511	644	404.	92.	17.
2000	21879.	11150.	10728.	2425	2525	1222	1139	540	676	400.	0.	0.

Table 5-24. Local Government Capital and Operating Costs Estimates (Cities and Counties Combined, 1980 Dollars, per 1,000 residents)

Elements		Capital	Operations
Sewer	treatment	$ 200,000	$ 25,000
	collection	800,000	
Water	supply	300,000	60,000
	storage	150,000	
	treatment	100,000	
	distribution	700,000	
Schools		2,400,000	420,000
Libraries		70,000	6,000
Administration		50,000	100,000
Parks and Recreation		430,000	20,000
Hospitals		200,000	N/A
Ambulance Service		20,000	10,000
Health, Mental Health, Social Services		165,000	260,000
Solid Waste		10,000	27,000
Public Safety		35,000	80,000
Detention Facilities		54,000	11,000
Fire Protection	(Vol.)	(70,000)	(4,500)
	(Paid)	(70,000)	(41,000)
Shop and Maintenance		60,000	N/A
Street and Roads	Municipal	2,000,000	50,000
	County	1,000,000	50,000
Assisted Housing		2,040,000	N/A
Storm Drainage		400,000	10,000
TOTAL (with paid fire dept.)		$11,349,000	$1,075,000
TOTAL (with vol. fire dept.)		11,349,000	1,038,000

Table 5-25. Projection of Public Costs Associated with Population Increases with and without 100,000-BPD NOSR Development for the Period 1981-2000

For Years	Net Population Increase		Public Costs (X $1000)						Total Increment Due to NOSR Development
			Capital			Operating			
	Without NOSR	With NOSR	Without NOSR	With NOSR	Increment	Without NOSR	With NOSR	Increment	
1981-1985	48,485	48,485	550,256	550,256	-	129,100	129,100	-	-
1986-1990	36,862	39,714	418,347	450,714	32,267	420,007	424,861	4,854	37,221
1991-1995	20,572	32,793	233,472	372,168	138,696	533,172	608,174	75,002	213,698
1996-2000	2,513	3,894	28,520	44,193	15,673	564,309	649,325	85,016	100,689

Assumptions:
- Capital Expenditures = $11,349,000/1000 new residents
- Operating Expenditures = $2,075/resident/year
- Expenditure is made in year cost is incurred. No bonding; no debt service
- Population associated with first NOSR facility arrives in 1987; second in 1989

The previous summary of public costs is based on standards prepared by Colorado's Division of Impact Assistance, historical information from local budgets, cost comparisons on recently completed projects, and review by appropriate state, regional and local agencies. These cost estimates assume that existing facilities and services are operating at their capacity and all costs will be incurred in providing services for the influx of each 1,000 new residents.

Nearly all portraits of revenues and costs related to oil shale development show a revenue shortfall for the first 10 to 12 years followed by a steady surplus of revenue over the life of the project. Recent examinations of public cost and revenue effects of energy development in Colorado confirm that public revenues may not be available in the early years of energy development when public capital costs for facilities and services are high. Moreover, jurisdictions which in the long term receive net revenue surpluses may not be the same as the ones which incurred the costs for energy-related growth. Finally, muncipalities, because of their high public service responsibilities and minimal access to property tax revenue, are more vulnerable to deficits than counties. These jurisdictional problems point to the need for developing creative public-private finance mechanisms and innovative impact mitigation programs. These issues are central to the NOSR Development Policy Program and the following analysis of public revenues in the NOSR region points to the feasibility of implementing a 100,000 BPD development option at NOSR 1 if provisions for front-end financing are realized.

Table 5-26 shows a projection of public revenues associated with facilities and related population increases with and without NOSR development at an assumed production capacity of 100,000 BPD.

The revenue projections shown in Table 5-26 comprise the following:

State Revenues

- Corporate income taxes payable by the project facility operators
- Individual income taxes payable by employees of project facilities (construction and operations) and induced work forces
- Severance taxes payable by mineral projects
- Public royalty payments, where applicable

Table 5-26. Projection of Public Revenues Associated with Project Facilities and Impact Population Increases with and without 100,000-BPD NOSR Development for the Period 1981 - 2000 (1980 Dollars, $000)

For	State Revenues			Local Revenues			Total Revenues		
Years	Without NOSR	With NOSR	Increment	Without NOSR	With NOSR	Increment	Without NOSR	With NOSR	Increment
1981-1985	176,157	176,157	0	198,452	198,452	0	374,609	374,609	0
1986-1990	546,692	551,906	5,214	652,647	655,491	2,844	1,199,339	1,207,397	8,058
1991-1995	712,589	795,618	83,029	794,771	888,399	93,628	1,507,360	1,684,017	176,657
1996-2000	732,678	904,424	171,746	810,500	971,570	161,070	1,543,178	1,875,994	332,816

The previous summary of public costs is based on standards prepared by Colorado's Division of Impact Assistance, historical information from local budgets, cost comparisons on recently completed projects, and review by appropriate state, regional and local agencies. These cost estimates assume that existing facilities and services are operating at their capacity and all costs will be incurred in providing services for the influx of each 1,000 new residents.

Nearly all portraits of revenues and costs related to oil shale development show a revenue shortfall for the first 10 to 12 years followed by a steady surplus of revenue over the life of the project. Recent examinations of public cost and revenue effects of energy development in Colorado confirm that public revenues may not be available in the early years of energy development when public capital costs for facilities and services are high. Moreover, jurisdictions which in the long term receive net revenue surpluses may not be the same as the ones which incurred the costs for energy-related growth. Finally, muncipalities, because of their high public service responsibilities and minimal access to property tax revenue, are more vulnerable to deficits than counties. These jurisdictional problems point to the need for developing creative public-private finance mechanisms and innovative impact mitigation programs. These issues are central to the NOSR Development Policy Program and the following analysis of public revenues in the NOSR region points to the feasibility of implementing a 100,000 BPD development option at NOSR 1 if provisions for front-end financing are realized.

Table 5-26 shows a projection of public revenues associated with facilities and related population increases with and without NOSR development at an assumed production capacity of 100,000 BPD.

The revenue projections shown in Table 5-26 comprise the following:

State Revenues

- Corporate income taxes payable by the project facility operators
- Individual income taxes payable by employees of project facilities (construction and operations) and induced work forces
- Severance taxes payable by mineral projects
- Public royalty payments, where applicable

Table 5-27. Net Local Revenues (Costs) in Impact Region with and without 100,000-BPD NOSR Development for the Period 1981-2000 (1980 Dollars, $000)

For	Local Costs		Local Revenues		Net Local Revenues (Costs)	
Years	Without NOSR	With NOSR	Without NOSR	With NOSR	Without NOSR	With NOSR
1981-1985	679,356	679,356	198,452	198,452	(480,904)	(480,904)
1986-1990	838,354	875,575	652,647	655,491	(185,707)	(220,084)
1991-1995	766,644	980,342	794,771	888,399	28,127	(91,943)
1996-2000	592,829	693,518	810,550	971,570	217,721	278,052

- o Sales and use taxes payable by projects and individuals
- o Miscellaneous revenues (e.g., alcohol beverage, motor fuel, and cigarette taxes)

Local Revenues

- o Ad valorem property taxes on industrial, commercial, and residential property payable by projects, other businesses, and individuals to counties, towns, school districts, and special districts
- o Sales and use taxes payable by individuals to counties and towns, where applicable
- o Miscellaneous revenues (fees, fines, other charges)

Table 5-27 shows projections of the net fiscal effect on local communities in the NOSR region of project activity, both with and without NOSR development. It should be noted, however, that these projections illustrate only local revenues versus local costs and that no intergovernmental transfers are portrayed, and to this extent the projections tend to overstate the local deficits occurring in the early years of all projects.

5.3 UNAVOIDABLE ADVERSE ENVIRONMENTAL EFFECTS

If developed, each technology alternative would have certain adverse and unavoidable environmental impacts. Measures are available to mitigate the adverse effects of each alternative and are identified in Section 5.1. Much of the data presented in Section 5.1 represent the emissions which can be expected after available control measures have been taken. This section identifies those adverse environmental effects which would result from implementation of alternatives after available control technologies and other mitigative measures have been applied.

As discussed in Section 3, emissions must be related to existing conditions in order to determine environmental impact. This has been done only in a general way, as in the case of air quality in which modeling of each reference case has not been performed. However, general impacts have been identified for each alternative to permit comparison, and are presented and compared below, based on information currently available.

The unavoidable adverse environmental effects of the reference cases for NOSR 1 development and oil shale development on other lands are very similar. Each case would result in some degradation of air quality after controls have been applied. Air pollution should not affect the local ecology significantly but will affect visibility and may alter scenic values. Water quality should not be adversely affected, although significant harm could result if spills occur. Decreased water availability may have adverse effects on flora and fauna, and water use may adversely affect the hydrology of the area. Hydrologic effects would be highly significant because water is in short supply in this region. Large areas will be required for disposal of solid wastes. The effectiveness of spent shale reclamation is uncertain. Spent shale will alter the topography and change habitats, thus affecting the occurrence and distribution of some plants and animals. Increased human activity and changes in habitats will affect animal communities and may decrease populations through increased competition. High temperature operations and flammable liquids will pose safety hazards. Contact with hydrocarbons and polycyclic organic matter may have adverse health effects, including carcinogenesis. Shale oil appears to pose a greater risk than conventional petroleum products but a lesser hazard than coal liquids. Results are uncertain at this time but further study is in progress. Oil shale development will have significant socioeconomic impacts due to the rural nature of the area to be developed. Significant population increases will place demands on communities to provide goods and services. Colony has planned community development and will provide tax revenues. The seriousness of the impact of NOSR 1 development will depend on which policy options are chosen and on the adequacy of Federal Impact Assistance or payment in lieu of taxes to help communities cope with increased demands for services. If NOSR is leased, it should generate sufficient revenues to cover costs.

No adverse effects will result from the reference cases for increased conservation. This alternative should reduce air pollutant emissions from the transportation sector and result in an improvement in ambient air quality. This alternative may affect the service station industry through a small decrease in gasoline pumped, but no socioeconomic analysis has been attempted.

Air quality may be degraded by combustion of crude oil for steam generation for EOR. This is the most significant adverse environmental effect of recovery of heavy oils by steam injection in Kern County, California. Air quality considerations may in fact restrict the level of EOR production in Kern County. There is also a possibility that water quality would be degraded by spills and by leakage of produced oil or brine into other formations through faulty casings. Large areas of land will be required for EOR, the productivity of which may be reduced by EOR activities. Workers will be exposed to safety hazards related to high temperature and pressure operations. Contact with crude oil may also have adverse health effects. Socioeconomic effects of EOR should be minor.

OCS operations will degrade local air and water quality through routine operations but the impact of this is not expected to be serious. Marine productivity is actually expected to be increased in the vicinity of platforms because the platforms serve as artificial reefs. Disposal of drilling muds and cuttings and disturbance of bottom sediments during the laying of pipelines will affect benthic organisms. The most serious adverse effects will occur if there is a large oil spill. Measures may be taken to lessen the likelihood of spills occurring but they are not completely avoidable. If a large spill occurs it will degrade water quality and possibly air quality as well. Volatile fractions of the crude will have toxic effects on organisms shortly after the spill and residues may make habitats unfit for several years. If spilled oil reaches coastal estuaries, a very productive biological community would be disrupted. OCS operations pose safety hazards to workers due to the possibilities of fires, explosions and blowouts on an offshore platform. Exposure to crude oil may also have adverse health effects. OCS development will take place in a developed area and should not have significant socioeconomic effects.

Coal liquefaction will degrade air and water quality. Standards for particulates, SO_2, and photochemical oxidants are already exceeded in the general area. Air quality could be further degraded by plant emissions. Sulfur dioxide emissions will combine with atmospheric water vapor to produce acid rain which will further aggravate high acidity in surface waters. Water quality will be adversely affected by acid mine drainage and, if they occur, by product spills. A significant area of land will be required for solid waste disposal, though not as large an area as is required for oil shale. Long-term health effects are of concern due to the carcinogenic potency of some constituents of liquefaction products. Preliminary data seem to indicate that coal liquids pose a greater chronic health hazard than shale oil or petroleum (see Section 5.1.6). Carcinogens are contained in some high boiling products and may also be released in small quantities as air pollutants. High temperature and pressure operations also pose safety hazards. Underground mining may cause ground subsidence and also disrupt aquifers. Coal liquefaction is the most labor-intensive alternative and would create a very large demand for increased goods and services. Project-generated revenues should not offset the public service costs and social impact of this alternative.

Production of ethanol from grain may cause minor degradation of air quality after controls have been applied. Most air emissions from ethanol production come from the combustion of coal to supply process heat and distill the product. Central Illinois is nonattainment for TSP and hydrocarbons (oxidants), and parts of the region are nonattainment for SO_2. These are the primary pollutants from ethanol production and may have adverse effects. The most significant water quality effects will be caused by agricultural runoff from the 5,000 square miles of land used to grow corn required by the 50,000 BPD case. Good management practices can reduce this impact but not avoid it. Ethanol production does not pose serious health or safety hazards. Public service costs will exceed revenues from ethanol production, producing an adverse socioeconomic impact.

5.4 RELATIONSHIP BETWEEN SHORT-TERM USES OF THE ENVIRONMENT AND THE MAINTENANCE AND ENHANCEMENT OF LONG-TERM PRODUCTIVITY

Short-term recovery of shale oil on NOSR 1 or the Colony site may adversely affect the long-term productivity of significant areas of land required for disposal of spent shale. If canyons are used for shale disposal, their filling will eliminate certain habitats, thus decreasing biological productivity and changing plant and animal occurrence and distribution. The effectiveness of spent shale revegetation is not well established. If groundwater is contaminated by leachates from spent shale, this will also reduce long-term productivity in an area of water scarcity. Chronic health effects would decrease human productivity. The NOSR 1 appears to be more biologically productive than the Colony site, and effects will therefore be more pronounced.

If increased conservation were practiced in place of developing other alternative energy sources, the short-term curtailment of resource use would extend the long-term availability of energy resources.

Enhanced oil recovery increases the amount of oil recoverable from an oil field. EOR may limit the productivity of the surface for uses such as farming by close placement of abandoned wells and soil contamination resulting from spills.

A large oil spill during OCS operations could lower marine productivity for several years by contaminating habitats with oil residues. If a spill were to reach estuarine areas their productivity might be lowered. Oil may kill young fish and affect future populations for several years. If a spill affected marine mammal populations, effects could last for many years because the populations are low. However, OCS production also will increase productivity in the vicinity of platforms by creating artificial reefs which serve as habitats for many species. This effect would last as long as the platforms were in place.

Acid mine drainage associated with coal mining for liquefaction will reduce the long-term productivity of surface waters due to reduced water quality and decreased biological productivity. Disposal of large volumes of waste may affect productive uses of land and may indirectly degrade water quality through leaching. If chronic health effects occur due to production and use of liquid fuels from coal, long-term human productivity would be adversely affected.

Increased use of agricultural land for corn production to produce ethanol could reduce long-term agricultural productivity by removing plant nutrients and trace elements from the soil. This effect can be mitigated by using good management practices and applying fertilizers.

One final consideration concerning the relationship between short-term use and long-term productivity is the effect fossil fuel-derived carbon dioxide (CO_2) will have on global climate. This is currently the subject of much scientific research and debate. Levels of atmospheric CO_2 are rising, and although the interrelationships are not clear, this appears to be related to increased combustion of fossil fuels and other activities such as increased clearing of land. Atmospheric CO_2 helps to regulate the earth's temperature. Scientists believe that a doubling of atmospheric CO_2 could increase surface temperatures an average of 2-3°C with effects accentuated in polar regions.[12] If this were to occur, significant climatic changes would follow. Although specific effects are difficult to predict, the results would probably dramatically decrease long-term productivity. Polar ice would melt, raising sea level and flooding low-lying areas. Climates suitable for agriculture would likely shift northward into areas having generally poor soils, thus affecting food production. These effects, though uncertain, warrant serious consideration.

Combustion of 50,000 to 200,000 BPD of any carbon based fuel is a very small increment of total fuel use and would contribute minimally to changes in atmospheric CO_2 concentrations. The cumulative effects of global fuel consumption, rather than incremental changes, will determine the CO_2 balance. Nevertheless, it is advisable to compare the relative production of CO_2 by the technology alternatives. Synthetic fuels generally release more CO_2 per unit energy than other fossil fuels such as natural gas because more energy is expended in producing a usable fuel. Production of CO_2 roughly correlates with thermal efficiency. Coal liquids produce the most CO_2 per unit energy. Shale oil also releases relatively large amounts of CO_2. Larger amounts than expected may be produced by direct-fired retorting because high temperatures may cause the carbonate in the shale to break down and release CO_2. Oil produced from EOR will release significantly more CO_2 than oil from OCS production because more energy is consumed to produce the oil. Biomass is a renewable energy source. This means that CO_2 released during ethanol production and combustion will be equal to CO_2 absorbed by corn grown to produce ethanol. However, a significant amount of fuel will be used to harvest the corn, and coal will be burned to distill the product. Conservation will result in direct reductions of CO_2 release to the atmosphere. Development of one alternative energy source in place of another will have an incremental effect on the atmospheric CO_2 balance. The significance of the effects will depend upon the relative contribution the fuel makes to global energy consumption and the amount of CO_2 it releases per unit of energy.

5.5 IRREVERSIBLE AND IRRETRIEVABLE COMMITMENTS OF RESOURCES

Oil shale development on either NOSR 1 or the Dow West site (Colony) will constitute an irreversible and irretrievable commitment of high grade oil shale deposits. Development also will entail a commitment of substantial water and air resources for the life of the projects. The clean air increment used by either of these projects would not be available to other industries while the projects are operational. Land required for spent shale disposal also will be irreversibly and irretrievably committed to oil shale development. Surface uses such as grazing and hunting will not be possible in the immediate vicinity of the facility. Activities such as exploration for oil and gas will not be precluded by oil shale development.

Increased conservation will reduce irreversible and irretrievable commitments of resources by postponing their use.

The oil produced and consumed by EOR would be irreversibly and irretrievably committed. Water resources also would be committed to EOR during the project operation. Clean air increments may be used up by EOR in Kern County during operation and would be unavailable for other uses until the project ended.

Oil recovered through OCS production would be unavailable to future generations.

Coal liquefaction will require commitments of coal and water. Land areas also would be required for solid waste disposal. Air quality increments would be committed during project operation.

Biomass conversion requires commitments of water and corn. Other commitments, including land for corn production, are reversible after project operation ends. The corn used as a feedstock is a renewable resource. That corn, of course, would not be available as food. However, the byproduct, distiller's dark grain, is usable as an animal feed supplement.

The energy alternatives requiring large facilities--coal liquefaction, oil shale and biomass/alcohol--will divert both capital and manpower from other development and activities, including the possible diversion of agricultural labor to oil shale jobs.

5.6 COORDINATION WITH FEDERAL, REGIONAL, STATE AND LOCAL LAND USE PLANS, POLICIES AND CONTROLS

Specific coordination with land use plans, policies and controls are not addressed because of the hypothetical or tentative nature of the reference cases. Any actual proposals for development must be coordinated with federal, state and local governments and must meet all applicable governmental standards and requirements. Other requirements for coordination will be addressed in a future site- and process-specific EIS.

No federal permits, licenses, or other entitlements are necessary to make the policy decision addressed by this EIS. Before actual development of NOSR 1 oil shale reserves may begin, Congressional approval of production would be obtained, as well as a number of federal and state permits. Federal and state permits also would be required prior to development of the other technology alternatives. The specific permits which would be required are not detailed in this EIS due to the general nature of the decision addressed by it and the fact that permit requirements will differ in different areas for various alternatives.

5.7 OTHER FACTORS

5.7.1 Energy Requirements and Conservation Potentials

The energy requirements of the technology alternatives are represented by process thermal efficiency in the technology configurations in Appendix B. This information is compared for the various alternatives in Section 3.8. Increased conservation will result in energy resource savings. Conservation potentials of the other alternatives have not been analyzed in this document.

5.7.2 Historic and Cultural Resources, Urban Quality, and the Design of the Built Environment

Historic and cultural resources, urban quality, and the design of the built environment have not been considered in this document. These concerns are site-specific in nature and will be considered in a site-specific EIS for NOSR 1 development. Generally, energy development will occur in rural locations rather than urban areas and should not adversely affect urban quality. Site-specific historic and cultural resources will be identified for NOSR 1 for consideration in a future site-specific EIS.

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6. PREPARERS

This document was prepared under the supervision of Mr. Donald Silawsky of the Office of Naval Petroleum and Oil Shale Reserves, DOE, by TRW Energy Department Group, McLean, Virginia, under its Management Support and Systems Engineering Contract No. DE-AC01-78RA32012. Notes on Mr. Silawsky and on the principal TRW contributors for particular areas follow below.

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Donald Silawsky joined the Office of Naval Petroleum and Oil Shale Reserves in 1980. As Program Manager for Environmental Affairs, he oversees all environmental activities for this office. Mr. Silawsky previously held positions with DOE's NEPA Affairs Division and the U.S. Environmental Protection Agency, and with the Naval Ship Research & Development Center. Mr. Silawsky received a B.S. degree in Physics in 1969 and a Masters degree in Engineering in 1971, both from Stevens Institute. In 1977, he received a Juris Doctor degree from Catholic University, and is a member of the District of Columbia Bar.

Herman I. Leon, Project Manager, has 35 years of experience. He received his Ph.D. in engineering at UCLA in 1955. Since 1975, he has performed systems analyses and project management functions in a variety of energy activities, including an electric utility technology assessment, energy cycle analyses, various technology assessments and priority studies, and fuel price and availability forecasts. He has been assigned to the NOSR project since its inception in 1978.

David D. Evans, senior chemist, Deputy Project Manager, has 15 years of experience, receiving his B.S. in chemistry at George Washington University. He has worked on energy projects since 1974, performing a wide variety of program planning and technical studies in various fossil energy areas, with special emphasis on petroleum and synthetic fuels.

Leslie L. Meyer, environmentalist, has had six years of experience since receiving his B.S. in biology from the College of William and Mary in 1976. He spent two years with the Smithsonian Institution's Chesapeake Bay Center for Environmental Studies, performing water, soil, and plant analyses in a study of diffuse sources of pollution. He was responsible for a soil moisture and temperature measurements project, and for a forest productivity investigation. Most recently, he has been conducting environmental impact assessments of energy technologies and providing environmental analysis support to energy strategy studies.

Preston D. Junkin is a 1977 graduate of the College of William and Mary, where he received a B.S. degree in biology. Following graduation, he worked for Litton Bionetics where he did toxicology research on industrial wastes, including shale oil production byproducts. Since July 1979 he has worked on several TRW studies, including impacts of proposed DOE projects relating to enhanced oil recovery, methane drainage and oil shale development.

John Dadiani, senior environmental scientist, has 15 years of experience. He has a B.S. in biology from Frederick College and an M.S. in environmental science from Tulane. He is currently the task manager for the NOSR air quality and meteorology monitoring program, and the baseline environmental characterization program. He has been involved in other oil shale projects as well as minerals mining, underground coal gasification, and cogeneration. Work in these areas has included air quality monitoring, impact assessment, permit support, and regulatory analysis.

Robert F. Robinson, senior economist, has 15 years of experience. He received his M.A. in economics from the University of New Mexico. He has been involved continuously in socioeconomic-related activities, and currently is a vice president at Tosco Foundation in Boulder, Colorado, responsible for their growth monitoring, forecasting and impact assessment system. With the Colorado West Area Council of Governments, he developed a computer-based model for forecasting economic and population growth. At Dames and Moore, he performed a variety of studies in engineering economics and in environmental analysis in environmental and applied earth sciences projects, including socioeconomic baseline and impact studies for several water, petroleum, uranium, coal and copper projects in Colorado, and socioeconomic impact comparisons of alternative energy sources for electric generation. He also was responsible for a variety of activities for the city and county of Denver, including housing, economic development and social service programs, and the development of the required legislation.

W. L. Bowling, senior staff engineer, has 35 years of experience. He received his B.S. in electrical engineering from the University of Oklahoma. He has had line supervisor responsibility, and performed a variety of new business venture studies for several firms. Since 1975, he has done energy planning and analysis in legislation and long-range strategies for fossil energy programs, and managed petroleum market studies.

Frederick P. Hayoz, economic analyst, has 17 years of experience. He received his M.S. in chemical engineering from Purdue University in 1971. He has performed extensive economic analysis in a variety of energy fields, including methane-from-coal technology and ethanol production. He has helped establish economic guidelines for computing synfuels costs and for consistent comparisons with alternative technologies.

Kevin J. Guinaw, environmental planner, received a B.S. in economics from St. Peter's College and a masters degree in Urban Planning and Policy Development from Rutgers University. He has eight years of experience and is the task manager for the Naval Oil Shale Reserves socioeconomic analysis with TRW. He has previously performed numerous environmental and socioeconomic studies, including a comparison of the environmental impacts generated by major synthetic fuel technologies, preparation of environmental monitoring plans for a proposed oil shale project and an assessment of local community energy use and alternative supply options.

Lindsay M. Tipton, head of environmental analysis, has 14 years of experience. She received her B.S. in biochemistry at the University of New Mexico in 1968, and has worked continuously in environmental activities, including developing an air pollution laboratory for the New Mexico Environmental Improvement Agency. With the Colorado Department of Health, Air Pollution Control Division, she contributed to vehicle pollution control legislation, directed a technical review of environmental impact statements, environmental assessments, land use plans and public transportation facility plans. At FEA, she contributed to the preliminary studies supporting orders converting power plants from oil and gas to coal. At TRW, she was the environmental planner for the Denver rapid transit system project, and has undertaken many environmental impact analyses of coal-conversion projects. She has contributed to DOE fossil energy program environmental activity planning, including environmental development plans for liquefaction and high and low Btu gasification projects. She has made extensive assessments of environmental consequences of energy development in all major energy technologies for several DOE studies.

APPENDIX A

DESCRIPTION OF THE AFFECTED ENVIRONMENT: NON-REFERENCE CASE ALTERNATIVES

The specific environments which would be affected by the selected reference case alternatives are described in the main body of this document. The following discussion presents a broader description, encompassing major areas of the nation which could be affected by each energy alternative. These include the Green River Formation in Colorado, Utah and Wyoming (oil shale production); various oil producing regions, both onshore and offshore (EOR and OCS oil production); eastern Utah (tar sands); the major coal-producing regions (liquefaction); and agricultural/silvicultural centers (biomass/alcohol).

A.1 LANDS OTHER THAN NOSR 1

Oil shale development on lands other than NOSR 1 could affect most other areas overlying the 16,500 square mile Green River Formation, which includes sections of Utah, Colorado and Wyoming. The thinness of eastern Devonian black shales makes their near-term exploration unlikely. Most development of the Green River Formation will concentrate in the Piceance Basin of Colorado, which contains 85 percent of known high-grade oil shale in the region.

Found in marlstone beds, the oil shales were deposited during the Tertiary period, during which a vast lake covered most of the area. Subsequent uplifting followed by erosion of the less-resistant sediments left an area dominated by steep cliffs rising several thousand feet above sea level. Elevation ranges from 5,000 to 13,000 feet. Seismic activity is minimal throughout most of the area, increasing slightly in the Utah portion.

The climate is semiarid to arid, with annual precipitation ranging from 12 to 24 inches in the Piceance Basin of Colorado, to 7 to 21 inches in the Green River and Washakie Basins of Wyoming. Water supplies depend upon major rivers in the area, which include the Colorado, Green, White and Yampa Rivers. Most streams are intermittent. Almost all surface water is part of the Upper Colorado River Basin system. Water flow is extremely variable and subject to salinity problems. Water is largely committed to irrigation and stock watering. Groundwater availability varies throughout the region, and has not been thoroughly studied in most areas. It appears to be more abundant in Colorado's Piceance Basin, where it is grossly divided into upper and lower aquifers, split by the Mahogany zone. Groundwater quality tends to be low throughout the oil shale region and high in total dissolved solids and salinity.

Air quality is very good throughout most of the area. Occasional short-term violations occur as the result of natural dust (total suspended particulates) and hydrocarbon aerosols (non-methane hydrocarbons). Local areas in Sweetwater County, Wyoming, and Grand Junction, Colorado, are designated as non-attainment for TSP. There are 24 mandatory Class I areas in Colorado, Utah, and Wyoming, two of which are within the oil shale region.

Regional temperatures range from -9.4F to 72.3F (annual minimum and maximum), with the number of frost-free days varying from 90 to 190 days/year, depending on location and altitude. Distribution of the sparse vegetational cover is determined chiefly by topography and water requirements. Sage brush, low shrubs and grasses predominate in the lower regions, while small trees such as pinon pines and junipers are scattered throughout. The Piceance Basin is the wintering ground for a major herd of mule deer. Wild horses are found in the oil shale region, chiefly in Wyoming. Four endangered species, the black-footed ferret, the bald eagle, the American peregrine falcon and the whooping crane (migratory) also live in the oil shale region. The human population density is quite low throughout most of the area, and includes a small Indian group in Utah.

A.2 ENHANCED OIL RECOVERY

Enhanced Oil Recovery (EOR) has the potential to affect all U.S. inland oil-producing regions, and some offshore sites. This discussion focuses on five major oil-producing regions: southern California; Oklahoma-Texas-Louisiana; the Rocky Mountains; the Midwest, and Appalachia.

California

Large quantities of heavy oil in southern California make this region a prime area for enhanced oil recovery. Most of the oil lies in the 12- to 20-mile-wide coastal plan of the Los Angeles Basin, which is covered by thick alluvial deposits consisting of sand, silt, clay, and gravel. Approximately 98 percent of the oil is located in sand or sandstone.

Major faults lie across the Los Angeles Basin in a northwest direction, and the area has a high seismic risk potential. Extensive oil field operations in the area have resulted in ground subsidence of up to 29 feet. However, repressuring efforts have arrested the subsidence and in some areas have produced a small degree of rebound.

Harbor water quality, once damaged by discharges of oxygen-deficient oil well brines, has largely recovered now that these practices are banned. Man-made islands produce offshore oil, which is generally brought ashore by pipes buried beneath the harbor bottoms.

Due to extensive development, major oil-producing areas are largely devoid of all but domestic animals and extremely tolerant plant species. Emissions from vehicles and major metropolitan areas have combined with low wind speeds and temperature inversions to create areas blighted by frequent air pollution episodes. Standards for photochemical oxidants, NO_2 and CO generally are violated throughout the South Coast Air basin. Several mandatory Class I areas exist in southern California.

Texas, Louisiana and Oklahoma

A large portion of the nation's oil originates in the tri-state region of Texas, Louisiana and Oklahoma, with some production from other nearby states. Southeast Texas and Louisiana share a number of characteristics, and are discussed separately from the mid-continental region of West Texas-Oklahoma.

Gulf Coast

The Gulf Coast in Southeast Texas and Louisiana contains series of low ridges parallel to the coast, flatlands and wetlands. Oil reservoirs may occur at depths of 22,000 feet. Numerous salt domes are found in the region, especially in Louisiana. Fault zones running east-west occur in the Louisiana coastal plain. The Balcones fault borders the Texas coastal plain.

The Gulf Coast experiences considerably more rainfall than the mid-continental oil region, with annual averages of 24 to 56 inches in Texas and 48 to 64 inches in Louisiana. Tropical storms are not uncommon, and hurricanes occur on the average of once every four years. Several areas in Louisiana and Texas have non-attainment status for photochemical oxidants. Particulates are a problem in some Texas coastal areas. Although the Mississippi River traverses the region, water quality is poor near industrial and urban centers. Coastal aquifers suffer from intrusion of ocean water and salt dome contamination. However, groundwater quality is good in northern Louisiana, and available in numerous aquifers. Extensive groundwater usage and oil production are blamed for significant subsidence in the Texas Gulf Coast. Several endangered animal species reside in the two states.

Oil production is a major industry in both Texas and Louisiana, employing 150,000 and 62,000 workers respectively. High unemployment characterizes the region, particularly Louisiana, where it reaches 10 percent in some parishes (counties).

Mid-Continental Region

The oil producing portion of West Texas and Oklahoma is considerably drier than the Gulf Coast region, receiving 16 to 20 inches of rain annually. Oil reservoirs are composed chiefly of sandstone or carbonate. Geology is particularly complex in Oklahoma, where reservoirs may be present at several levels in a single field. A number of major faults occur in the region. Earthquake potential is low, becoming moderate only in North Central Oklahoma.

Water availability is a serious problem in West Texas and western Oklahoma. Numerous aquifers produce usable water, but are in danger of depletion. Surface and groundwater quality varies considerably in the region, with degradation occurring as the result of both man-made (e.g., oil wells) and natural (e.g., salt deposits) causes.

Air quality is generally good, although TSP, photochemical oxidants and carbon monoxide standards are violated in certain urban sections of Oklahoma. Several mandatory Class I areas are located in the region.

Texas is the nation's largest oil producer, while Oklahoma ranks fourth. The majority of the land area in both states is devoted to agriculture, and is chiefly used for grazing.

Midwest: Illinois

The vast majority of Midwestern oil is located in southern Illinois, where it is found mostly in upper Mississippian sandstones and lower Mississippian limestones and sands. Regional topography consists mostly of level or rolling plains. Numerous faults occur in the Illinois Basin, which is considered to have a moderate seismic risk potential. Eighty percent of the state's land area is devoted to agriculture.

Water is abundant in the region. Major aquifers are found in unconsolidated glacial drift and alluvial deposits, and in bedrock. However, certain parts of central and southern Illinois lack sufficient groundwater for municipal-industrial uses. The southeastern part of Illinois is in the Ohio River Basin, while the rest of the state lies in the upper Mississippi River Basin. Surface water quality varies considerably, depending on the rate of flow. Runoffs from agriculture and coal mining contribute to violations of standards, and in some cases have affected groundwater. The climate in the oil-producing part of the state is less harsh than the northern part, with an average annual snowfall of 12 inches.

Although air quality in the oil-producing region is considerably better than in the northern part of the state, several counties in southern and central Illinois violate standards for TSP and/or photochemical oxidants. No mandatory Class I areas exist in the state. Slightly over 10 percent of the population resides in the southern part of the state, while 83 percent lives in urban areas, predominantly in the north. Oil production in 1978 employed 5,753 workers. Several endangered bird species inhabit the state.

Appalachian Region

The main oil-bearing province in the Appalachian region is found in the 40- to 70-mile wide geosyncline which trends in a SW direction from Southwestern Pennsylvania to West Virginia. The area is part of the Appalachian Plateau, and consists of a series of ridges, foothills and valleys. No major faults occur in the area, and the climate is mild, tending toward more severe winters in the northern portion. Relatively high topographic relief has concentrated urban centers, industry and agriculture in the flood plains and other low areas. Mining is a leading industry, producing coal, gas, limestone, sand, gravel, and salt.

Numerous regional non-attainment areas exist for particulates and photochemical oxidants, with fewer non-attainment areas for SO_2. Several mandatory Class I areas are found in West Virginia. Runoff from coal mining and agriculture has resulted in water quality degradation in some areas, where total and fecal coliform, iron, and manganese are found in high concentrations. The Monongahela River in West Virginia is particularly affected by mining.

Rocky Mountain Region

Oil reserves in this region remain largely untapped, even by primary methods of recovery, but the area is rapidly increasing its role in energy production. Wyoming is the leading oil producer, oil being frequently found in folded anticlinal traps. Thrust faults are found throughout the region, which is considered as a low to moderate seismic risk. However, fluid injection in the area has resulted in minor earthquakes.

Regional topography consists of high mountain ranges and steep river valleys, yielding to plains in the east. Wildlife is abundant, and includes several endangered species (e.g., the black-footed ferret and the Northern Rocky Mountain wolf). Yellowstone and Grand Teton National Parks are located in Wyoming, as well as six national forests.

Overall air quality is excellent, with most areas in attainment, except for a few industrialized sectors. Several mandatory Class I areas are located in the region. Surface water originates largely from snowmelt, though groundwater is the major source in late summer, winter and fall. Surface water quality is generally good; however, irrigation return and erosion have led to sedimentation, turbidity and salinity in some areas. Trace metal concentrations are high in both soil and water. Groundwater is used chiefly for rural domestic and livestock supplies. Total dissolved solids average 500 ppm in Wyoming at depths less than 1,000 feet, increasing to greater than 2,000 ppm in deeper aquifers.

A sparse population of 3.4/square mile (Wyoming, 1970) already has created problems in areas undergoing rapid energy industry development. At times, populations grow faster than waste water treatment capacity or other vital services. In 1977, 12,000 workers were employed in oil and gas production. Mineral production is the largest Wyoming industry in tax dollars generated.

A.3 OUTER CONTINENTAL SHELF (OCS) OIL PRODUCTION

Outer Continental Shelf oil production is potentially able to affect marine and coastal environments of the Continental United States and Alaska. This section gives brief descriptions of potential OCS oil well sites (other than the Gulf of Mexico), centering on the region's meteorology and basic oceanography. The OCS is discussed under the following regional divisions: Atlantic; Pacific; Southern Alaska; Bering Sea, and Arctic. Regional discussions do not imply the presence of proven reserves in each region. The Gulf of Mexico is discussed in Section 4.5.

Atlantic Region

The gradual slope of the Atlantic Continental Shelf is broken by 190 canyons. Mass sediment movement may occur at canyon heads or at the upper slopes as the result of natural underwater or surface phenomena. Migratory sand waves and strong tidal currents occur in the north Atlantic region. Except for the northward flow of the Gulf Stream, currents in the Mid- and South Atlantic are relatively weak and are influenced by spring stream influx or winter winds. Complex local eddies are common. The median significant wave height is four feet in winter and two feet in summer, with waves of 57 feet occurring on an average of once every five years. Storms are most common between November and April. Extratropical cyclones generally occur between 30 and 40 degrees north latutide, between October and April. In the south Atlantic, tropical cyclones occur between late May and early December.

Commercial fishing is extremely important to the area, particularly in the North (Georges Bank fishery off Cape Cod) and Mid-Atlantic. Other activities include shipping (USGS shipping lanes have been established for major ports), recreation, NASA and military testing, and interim dumping. The coastal wetlands provide spawning grounds for many commercial and non-commercial fish. Soft substrate benthic habitats predominate the shelf bottom. The 195-mile coral reef system off the Florida coast is the North American Continent's only major coral ecosystem. Endangered species in the

Atlantic region include seven mammal, five turtle and two coastal species. Two subsea sites are presently protected for historical reasons.

Pacific Region

The Continental Shelf slopes gradually in the northern Pacific, interrupted only occasionally by undersea canyons. The topography becomes more complex off southern California, where much of the oil production is anticipated. Several faults, some considered active, cross portions of the Pacific region. Although waves are generally moderate, occasional tsunamic waves have caused significant damage along the coast.

The California coastal region represents a transitional area between subtropical southern waters and the northern temperate zone, resulting in a diversity of aquatic fauna. Upwelling of subsurface water and nutrients results in a large phytoplankton bloom in spring or summer (depending on latitude), followed by sharp increases in zooplankton. Several endangered animal species inhabit the region, including seven whale (migratory), and four turtle. The sea otter and several seal and sea lion species are present. Commercial and sport fishing and shipping are important water uses. Prevailing summer winds in the region tend to push surface emissions toward shore, where they may contribute to poor air quality in much of California.

Southern Alaska Region

The Gulf of Alaska coastal area is one of high relief and glaciation. The marine environment is subject to severe geologic and meteorologic influences. Earthquake potential is relatively high, with an accompanying potential for mass seabed movements and tsunamic waves. Waves and winds are normally high. Cook Inlet is the site of sporadic mudslides and landslides, and contains five volcanos, three of which have erupted in the last 21 years.

Water and air quality are generally good. A large phytoplankton bloom occurs in the spring. Zooplankton serve as the main food supply for numerous species of fish and some marine mammals. Endangered species in the area include seven types of whale, three bird species (over 100 bird colonies inhabit the region), four plants and one terrestrial mammal. The Gulf supports the largest commercial fishery off Alaska. Most of the Gulf is ice-free during normal years except for Cook Inlet, which contains loose pack ice throughout four months of the year. Regional waters are of considerable depth, and numerous deepwater ports line the coast. Many sites of potential archeological importance are believed to lie along the Alaskan coast.

Bering Sea Region

The Bering Sea region is considerably colder than the Alaskan Gulf, covered with ice for half the year, and 60 to 70 percent ice-bound during the coldest months. Its waters generally are shallower than the Gulf's, but are 2.3 miles deep in some areas. Shallow faults, unstable bottom sediments, and subsea permafrost represent potential hazards to oil production. Some volcanic activity occurs in the Aleutian chain. Seismic events tend to be of a lesser magnitude than further south.

Many of the animal species of the Alaskan Gulf are also present in the Bering Sea, where 25 species of marine mammals are found, along with an estimated 27 million seabirds.

Major employers in the region include the federal government, the fishing industry, and service industries.

Arctic Region

The Arctic Region has low seismic risk and no volcanic activity. Pack ice, present throughout the year, creates gouges in the sea floor up to 15 feet deep as it approaches land. Storm waves are tempered by the pack ice, causing less disturbance than to the south. Beach erosion is significant in the region.

Air and water quality are pristine in the Arctic. Fewer fish and marine mammal species inhabit the region, but it remains an important habitat for many marine animals and seabirds. Commercial fishing is practical on a smaller scale than in the south. Oil and gas production represent the largest regional economic activity, concentrating on the coast at Prudhoe Bay and on the National Petroleum Reserve.

A.4 TAR SANDS

Thirty-nine concentrated deposits (>1 million barrels) of tar sands have been identified in the United States (Energy Fact Book, USN, p. 196).

Although concentrated deposits are found in California, Kentucky, New Mexico and Texas, 90 to 95 percent of the U.S. tar sands resource is confined to Utah. The rugged terrain of the Colorado plateau predominates in eastern Utah where the tar sands are located. The Utah climate is semi-arid to arid, with water supplies dependent on such major waterways as the Colorado, Green and White Rivers. Snowmelt and summer thunderstorms contribute to the supply, but most water enters from outside the state. Much of the surface water is committed to irrigation and stock watering. Salinity is a perennial problem in the Colorado river system. Erosion is a problem in the region. Groundwater is not abundant, and generally of poor quality.

Air quality is good throughout most of the region, but non-attainment areas for photochemical oxidants, particulates and carbon monoxide are present in the north-central, and western parts of Utah. Cattle and sheep ranching make primary demands on land use. Regional population is mostly sparse and includes a small Indian percentage.

A.5 COAL LIQUEFACTION

The source of the following information on potential coal liquefaction sites is, in large measure, from the Alternative Fuels Demonstration Program Final EIS (ERDA, 1977), which provides detailed material on the subject.

This source document describes environments of the five major coal-producing regions: Appalachia; Eastern Interior; Fort Union; Powder River; and Four Corners. Each region is capable of supporting several coal-based synthetic fuel plants with a 30-year supply (790 million tons) of bituminous coal or its equivalent in subbituminous coal (1,050 million tons) or lignite (1,500 million tons). The five regions are represented by a wide diversity of physical, biological and socioeconomic factors. Coal characteristics differ markedly among regions. The percentages of elemental sulfur and pyritic sulfur are highest in the bituminous coals of the Appalachian and Eastern Interior Coal Regions. However, sulfur content of one percent or less is typical of the Western bituminous coal and lignite. Heating values of bituminous coals of the Appalachian and Eastern Interior regions also are higher than those of Western subbituminous coal and lignite. Additionally, the moisture content of the Appalachian coal is considerably less than those of the other regional coals. Western coals generally have higher moisture content than both Appalachian and Eastern Interior bituminous coals.

Coal Regions

Appalachian Region

The Appalachian Coal Region extends about 800 miles from northern Pennsylvania to western Alabama in a mountainous topography and includes portions of Pennsylvania, Maryland, Virginia, West Virginia, Ohio, Tennessee, Kentucky and Alabama. The region is defined by the Appalachian Mountains, which rise from a relatively low level of plains, valleys, and plateaus, with few peaks reaching as high as 5,000 feet. Climate is relatively humid, with high precipitation that ranges from 40 to 50 inches a year. A wide variety of crops flourish without irrigation. Surface water supplies are abundant and, for the most part, readily accessible. However, industrial and municipal water pollution and contamination from mine drainage are especially severe. Air quality varies considerably throughout the region with non-attainment areas for photochemical oxidants widespread in Pennsylvania and occurring in other regional areas. Particulates create problems in scattered Appalachian areas.

The Appalachian Region contains many deciduous forests, with a wide range of hardwood and coniferous trees, shrubs, grasses and crops. While there is a variety of wildlife, many big game species of the western regions are lacking, and in Appalachia's southern oak-hickory forests, animal populations tend to be low. Among land uses, cropland, pasture, and forestry predominate. Relative remoteness from Eastern metropolitan centers and the low productivity of small agricultural holdings can make it difficult to earn a livelihood. Much of the population is economically dependent, directly or indirectly, on coal.

Eastern Interior Region

The Eastern Interior Region is characterized by flat topography with some gentle relief. The region includes southern portions of Illinois and Indiana and northwestern Kentucky. Like the Appalachian Region, it experiences hot, humid summers and cold, humid winters. Water supplies are abundant. Air quality is variable. Non-attainment areas for photochemical oxidants and particulates surround urban areas. The region belongs to the northern temperate portion of the grassland biome. Important types of vegetation include tall grass prairie and oak-hickory forest. As in the Appalachian Region, pressur[illegible] of human habitation have eliminated the larger animals of the West and reduced the population of mammalian species. Primary land uses for the Eastern Interior coal region include agriculture, manufacturing (particularly machinery), and mining.

The Eastern Interior has a flourishing economy, with relatively low unemployment, generally adequate housing, and a relatively high median level of education. In addition, it is well serviced by utility and transportation lines.

Fort Union Region

The Fort Union Region in northeastern Montana, western North Dakota, and northwestern South Dakota lies in the Missouri Plateau of the Great-Plains Province. Adjacent to the Missouri River, drainage is well established over a broad expanse of gently rolling and terraced topography. It is characterized by climatic extremes, with a precipitation rage intermediate between that of the humid east and the arid Four Corners Region. Water use draws heavily upon major rivers, such as the Missouri, Yellowstone, and Little Missouri and their tributaries. Air quality is good.

The region contains grasslands, with isolated coniferous forests. Grazing and crop cultivation rely heavily on irrigation. Deer and other big game animals abound, as well as waterfowl from the central flyway which traverses the region. Primary land use is for agricultural and grazing purposes.

The Fort Union Region is sparsely populated, with only a relatively small available labor force. It has a significant Indian population, principally on the Fort Peck Reservation in Montana and the Fort Berthold Reservation in North Dakota. The population reflects agricultural traditions, with little urbanization or industrialization. Heavily dependent on agriculture, the economy is stable, supporting adequate living standards.

Powder River Region

The Powder River Region of southeastern Montana and northeastern Wyoming greatly resembles the adjoining Fort Union Region. It also belongs to the Great Plains physiographic province and is part of a broad synclinal basin between the Black Hills on the east and other mountains to the south and west. Biologic characteristics of the region differ from those of the Fort Union Region.

Like the Fort Union Region, the Powder River Region depends on agriculture, drawing heavily on irrigation by such major rivers as the Yellowstone and its tributaries, the Belle Fourche, and the Bighorn. Ambient air quality standards for oxidants and particulates are violated in several areas. Pasture and rangeland account for the largest land use. It is a land of frontier and pioneer traditions and a sparse population. There is a sizeable Indian population represented by the Crow and Northern Cheyenne Indian Reservations.

Four Corners Region

The Four Corners Region, comprising parts of Colorado, Utah, Arizona, and New Mexico has an arid climate of cold winters and hot summers, with very low precipitation (8 to 12 inches per year). Physiographically, the Four Corners Region is characterized mainly by plateaus dissected by canyons, stony relief, occasional ranges and desert plains. Water is limited, with heavy irrigational and industrial demands placed on surface water supplies, mostly from the San Juan and Little Colorado tributaries of the Colorado River. Air quality is variable, with non-attainment areas for carbon monoxide in northwestern New Mexico. Mandatory Class I areas occur in the vicinity of the Four Corners region. Biologically, it is an area of basic sagebrush, with grasslands and pinon-juniper woodlands. Both big game and small game mammals and birds are found.

As some other Western regions, the Four Corners Region is sparsely populated. Much of it is economically depressed, particularly those counties with high Indian populations. The Navajo, many of whom occupy reservation land in this region, constitute the largest Indian tribe in the

United States. Land use runs heavily to grazing, with some cropland that generally requires irrigation. Logging and mineral extraction contribute to the regional economy.

Like other Western coal regions, the Four Corners Region is widely used for hunting and other recreational activities and for touring those historical and cultural sites associated with settlement of the West and with Indian history. Spectacular scenery and geologic marvels, such as the Grand Canyon, characterize the Four Corners region to a greater degree than those of any other coal area.

A.6 BIOMASS/ALCOHOL

Energy from biomass implies potential impacts upon a large range of environments due to the diversity of biomass sources and production methods.

Direct combustion of agricultural and forestry residues, in the short term could affect the country's major agricultural and silvicultural regions. Over the longer term, development of energy farms could impact areas where forestry is not presently a major industry. The Southeast U.S. is a probable candidate for such development.

Anaerobic fermentation to produce ethanol could affect any areas which can produce corn, sorghums, sugar beets or sugarcane. Although most corn is grown in the Midwest corn belt (Iowa, Illinois, Indiana, Ohio), the Southeast produces large crops and could be the site of major land-use conversions to corn production. Sorghums are grown largely in the Midwest and some Western states, while sugarcane is cultivated mostly in Louisiana and Florida. Sugar beets are grown from the midwest to the west coast, with a few western states leading in crop production. Changing needs for energy and food could cause major land-use changes in these agricultural areas, as well as in those presently employed in non-agricultural land use.

The manufacture of combustible products from oil or latex-bearing plants can affect agricultural areas in the Midwest, as well as more arid regions of the Southwest. Methane production from wastes via anaerobic digestion is not limited geographically, but would tend toward location near large population centers.

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APPENDIX B

Technology Discussions

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APPENDIX B
TECHNOLOGY DESCRIPTIONS

Appendix B provides a description of each representative case selected for the technology alternatives. It includes a description of the process, inputs and outputs, capital and operating costs (where available), manpower requirements, air emissions, solid waste and a measure of process energy efficiency. All of these characteristics are fairly straightforward, except energy efficiency. Several different definitions of efficiency are possible, each of which is useful for describing certain energy relations. Three of the more commonly used energy efficiency definitions will be used here (where possible), to describe and compare energy relationships among the alternatives. They are net energy efficiency, thermal or process efficiency, and system efficiency.

Net energy efficiency is a measure of the net recovery of energy of a project. It calculates the percentage of total energy recovered after external invested energy is subtracted. External energy is that energy which crosses the project boundary and must be drawn from the general economy. Net energy efficiency (E_N) can be represented by the formula:

$$E_N = \frac{\text{Gross Energy Recovered - Energy Invested}}{\text{Gross Energy Recovered}}$$

It is easy to conceptualize net energy analyses, but it is difficult and time consuming to do them. Net energy analysis considers primary or direct energy and indirect energy through secondary, tertiary and lower levels. Direct energy is by far the largest constituent, with secondary contributing a very small amount and lower levels contributing so little as to be generally not worth the effort to calculate. This conclusion is supported by the detailed net energy analysis described in Appendix C, in which it is shown that, for the NOSR oil shale alternative, direct energy is about 8.5% of output energy, whereas total indirect energy is about 1% of output energy. Since there is an uncertainty surrounding any energy efficiency analysis, direct energy usage alone is adequate for a reasonable comparison of alternatives. Net energy efficiency, as approximated by direct energy usage, is one of the measures used in Appendix B. This measure is expressed in terms of the number of barrels of oil equivalent of product per each barrel of oil equivalent invested.

Thermal or process efficiency is a measure of the recovery efficiency of the central conversion or extraction process. In the case of oil shale, it would be the retort. Thermal efficiency (E_T) can be represented by the formula:

$$E_T = \frac{\text{heating value of products}}{\text{heating value of feedstock + added fuel or electricity}}$$

Thermal efficiency does not consider all operations, such as mining and upgrading, which occur inside the project boundary.

System efficiency is a measure of the overall energy efficiency of the project. It considers all operations within the project boundary. Its factors include the thermal, conversion and extraction losses plus the externally supplied energy. System efficiency (E_S) can be represented by the formula:

$$E_S = \frac{\text{heating value of products}}{\text{heating value of feedstock extracted + external energy invested}}$$

Calculations are illustrated in Appendix B for each of the methods employed to estimate energy efficiency.

Appendix B references all sources for figures used in the alternatives description. Alternatives chosen are representative of their technologies as defined in the selection criteria on pages 3-1 and 3-2, and do not necessarily represent any programmatic preference for those chosen - only their suitability for programmatic EIS purposes. For example, direct liquefaction of coal was chosen over indirect liquefaction based upon the criteria mentioned. Considered, but not heavily weighted, was the fact that direct liquefaction products more closely corresponded to those from a theoretical oil shale plant on NOSR 1 than do products from indirect liquefaction. For purposes of comparison in this document, this would have little influence on the final outcome. This in no way implies any preference for either mode or, for that matter, for any of the representative cases described in Appendix B.

B.1 Technology - Oil Shale

Process - Vertical Direct-Fired, Vertical Indirect-Fired, and Revolving Fines Retorts/Room-and-Pillar Mining

Location - Naval Oil Shale Reserves (NOSR) 1 and 3, Garfield County, Colorado

Process Description (1, 2)

Oil shale is mined by room-and-pillar underground mining, sent to a primary crusher and a secondary crusher where it is sized to dimensions required by the retort (between ½ and 3 inches). Fines produced by the two crushing operations are collected for use in the fines retort.

Vertical Direct-Fired Retorts - Raw Shale of 1/2" x 3" size is continuously fed by means of a distributor to the kiln. The shale moves down the kiln through a mist formation and preheating zone, a retorting zone, a combustion zone, and, finally, a residue cooling and gas preheating zone. It is discharged through a moving grate which controls and maintains even flow. The processed shale is discharged at about 350°F, cooled to 200°F with water, moisturized by the addition of 10 weight percent water, and sent to a surface disposal area.

The shale vapors produced in the retorting zone are cooled to a stable mist by the incoming shale and leave the retort at about 140°F. The mist is sent to an oil scrubber where about 50 percent of the mist settles and is removed as liquid. The remaining vapors go to an electrostatic precipitator where the remaining mist is coalesced. The condensed oil is sent to a surge tank and then to the topping unit. The low Btu gas is in part recycled to the retort for combustion and heat supply. The remainder is sent to a Stretford unit to remove the hydrogen sulfide before continuing to the plant fuel system.

Vertical Indirect-Fired Retorts - The vertical indirect-fired retort system is similar to the vertical direct-fired system. The raw 1/2" x 3" shale enters the top of the kiln, passes through the preheating, retorting, and cooling zones before being discharged at about 350°F. The processed shale is cooled to 200°F with water, moisturized with 10 percent water, and sent to the disposal area.

Retorting of the shale is achieved by introduction of hot recycle gas (1300^{o}F) which is heated externally in a fired heater. Air is not introduced and the recycle gas has a heating value of about 850 Btu/scf which can be increased further by removal of CO_2. The main advantage of the indirect system is that the gaseous product, after the removal of H_2S and CO_2, has a high Btu value and is suitable for the production of H_2.

Fines Retort - The fines, 0" x 1/2"-size shale, are processed in a fines-type retort. The raw shale is preheated by direct heat exchange with hot flue gas from the solid heat transfer medium heater. The preheated raw shale is separated from the flue gas and sent to a rotating drum retort. Hot flue gas is incinerated in the preheat system to reduce trace hydrocarbons to less than 90 ppm in the discharge flue gas. The cooled flue gas is passed through a high energy venturi wet scrubber to remove shale dust before being vented to the atmosphere at about 125^{o}F.

Pyrolysis is accomplished in the rotating retort by solid-to-solid heat exchange between the preheated shale and the hot heat transfer material at a temperature of about 900^{o}F, which results in the conversion of kerogen to hydrocarbon vapors. The mixture leaves the retort and goes to a rotating trommel screen for separating the shale from the solid heat transfer material, which is then circulated back to the heater by means of a bucket elevator.

Warm flue gas from the stack of the steam superheater is used to remove residual dust from the solid heat transfer material circulation system. The dust is removed from the flue gas with a high energy venturi wet scrubber.

The processed shale is cooled in a rotating drum steam generator, moisturized in a rotating drum moisturizer, and transported by a covered conveyor to a processed shale disposal site.

The collected raw shale oil is then processed through a topping unit, visbreaker for atmospheric bottoms, and a hydrotreater. The resultant product is a light, sweet, readily pipelineable, premium quality feedstock.

Capital Costs (1) - $1.295 billion (1979 $)

See Appendix B

Operating Costs Per Year - $101 million (1979 $)

Manpower Requirements (1) - See accompanying chart

Operating Parameters (per day)

INPUT (1, 5)		50,000 BPD	200,000 BPD
Oil Shale	-	72,500 TPD (31 GPT)	290,000 TPD
Make-up Water	-	129,170 BPD	516,681 BPD
		(5,461 AF/Y)	(21,844 AF/Y)
Electric Power	-	1,446 Mwh/D	5,784 Mwh/D

OUTPUT

Products (1)			
Shale Oil	-	50,250 BPD	201,000 BPD
Low Btu Gas (83 Btu/SCF)	-	329,638,000 SCF/D	1.319 BSCF/D
High Btu Gas (850 Btu/SCF)	-	24,282,000 SCF/D	97,128,000 SCF/D
Sulfur	-	106 TPD	424 TPD
Ammonia	-	220 TPD	880 TPD
Water	-	28,457 BPD	113,828 BPD

Energy Efficiency (from Appendix C)

10^6 Btu

	DIRECT	INDIRECT	TOTAL
Ammonium Nitrate/ Fuel Oil	539.3	21.9	561.2
Diesel	2,282.6	190.5	2,473.1
Electric	17,350.2	1,789.0	19,139.2
Other	8,489.0	-	8,489.0
Capital Equip.	-	2,280.0	2,280.0
	28,661.1	4,281.4	32,942.5

$$\text{net energy efficiency} = \frac{\text{gross recovered energy} - \text{energy invested}}{\text{gross recovered energy}}$$

$$= \frac{339.6 - 32.9}{339.6} = 90.3\%$$

1 BOE invested yields 10.3 BOE of all products or 8.9 BOE of liquid products.

$$\text{Thermal Efficiency} = \frac{\text{heating value of products}}{\text{heating value of feedstock + added fuels}}$$

$$= \frac{339.6}{398.8 + 15.3} = 82.0\%$$

$$\text{System Efficiency} = \frac{\text{heating value of products}}{\text{heating value of extracted feedstock + invested energy}}$$

$$= \frac{339.6}{405.4 + 32.9} = 77.5\%$$

Emissions (3)

SO_2	-	1.1 TPD	4.4 TPD
NO_x	-	11.1 TPD	44.4 TPD
THC	-	0.8 TPD	3.2 TPD
Particulates	-	2.9 TPD	11.7 TPD
CO	-	2.0 TPD	8.0 TPD
Solid Waste (1)			
Spent Shale	-	58,875 TPD	235,500 TPD
Other	-	1,733 TPD	6,932 TPD

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(1) Shale Oil Production System Reference Case Study - Final Report, June 1979.

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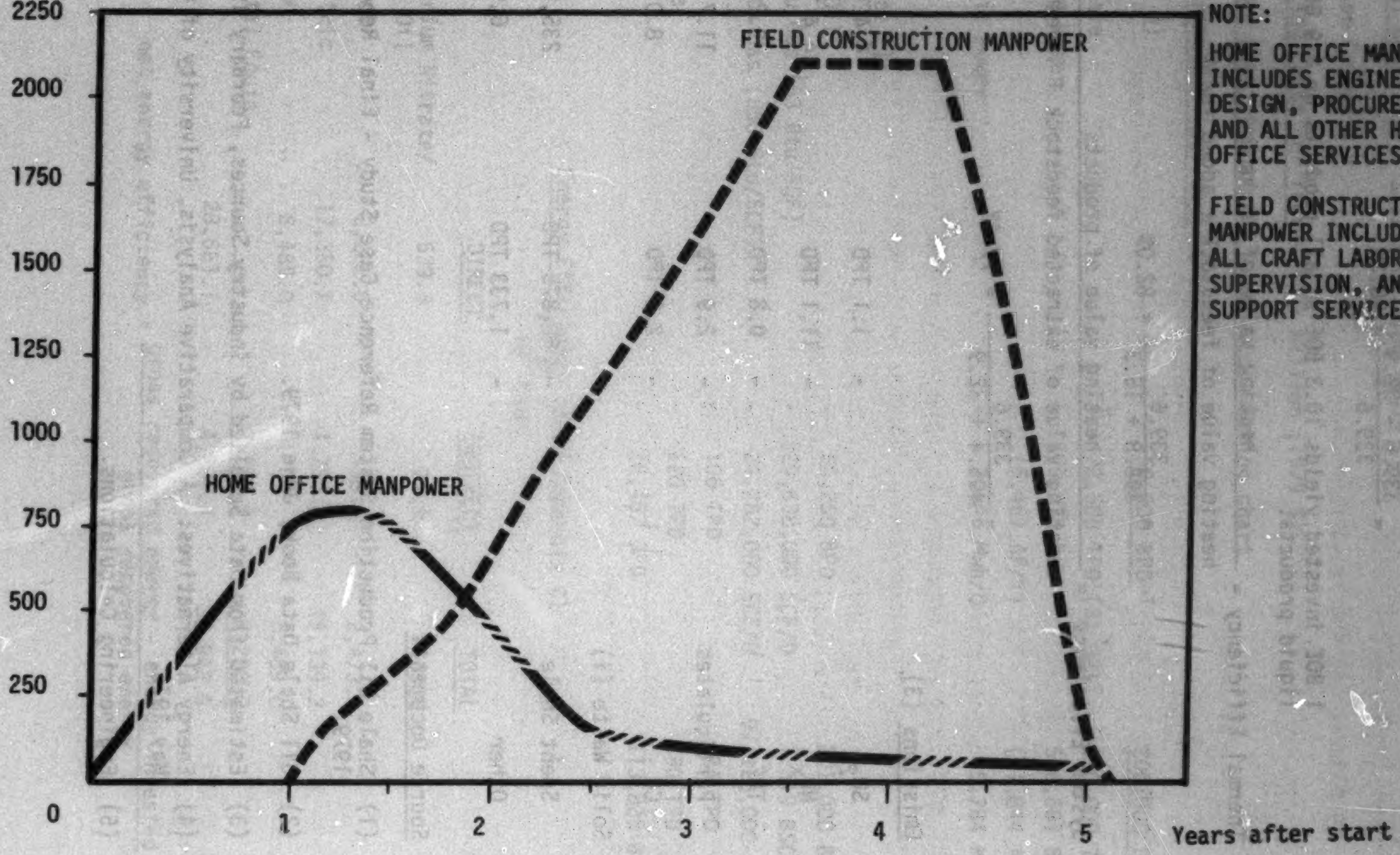

NOTE:

HOME OFFICE MANPOWER INCLUDES ENGINEERING, DESIGN, PROCUREMENT, AND ALL OTHER HOME OFFICE SERVICES

FIELD CONSTRUCTION MANPOWER INCLUDES ALL CRAFT LABOR, SUPERVISION, AND SUPPORT SERVICES

Figure B-I. Manpower Profiles for NOSR

B.2 **Technology:** Conservation

Process: Transportation

Location: Denver

Process Description:

Only light-duty, gasoline powered, passenger cars are considered in this analysis. Total fleet emissions for EPA criteria pollutants are projected for 1990 using emission factors developed by EPA. The reduction in emissions is calculated from a national savings of 50,000 BPD of gasoline.

This fuel efficiency improvement is assumed to result from a decrease in vehicle weight only, and thus factors which would change the vehicle emissions, such as engine modification or changes in vehicle use, need not be considered here. The reduction in emissions which would result from using less gasoline are also calculated for the Denver area.

Emissions[1]

Potential daily reduction (controlled)

National	**50,000 BPD**	**200,000 BPD**
CO	253 tons/day	1,012 tons/day
HC	33 tons/day	132 tons/day
NO_x	73 tons/day	292 tons/day
SO_2	7.7 tons/day	31 tons/day
Particulates	2.3 tons/day	9 tons/day
Denver Metropolitan Area Portion		
CO	0.76 ton/day	3.04 tons/day
HC	0.10 ton/day	0.40 ton/day
NO_x	0.22 ton/day	0.88 ton/day
SO_2	0.02 ton/day	0.08 ton/day
Particulates	0.007 ton/day	0.28 ton/day

Net Energy Efficiency

Since energy is not produced, a net energy efficiency cannot be calculated.

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[1] "Compilation of Air Pollutant Emission Factors", 3rd ed., AP-42, EPA, August 1977.

B.3 Technology - Oil Shale

Process - TOSCO II/room-and-pillar mining

Location - Dow West (Colony) property, Garfield County, Colorado

Process Description

Retorting in the TOSCO II process is achieved by direct contact between hot ceramic balls and preheated oil shale. Raw shale that has been crushed to less than 13 mm (1/2 in) is preheated by hot flue gas from a ball heater in a dilute-phase lift pipe system. The lift pipe system serves as a thermally efficient heat transfer device capable of handling a wide range of particle sizes with a low pressure drop. The preheated shale is then fed to a pyrolysis drum. Retorting of the oil shale is achieved by solid-to-solid heat transfer between the shale and hot ceramic balls, flowing concurrently through the rotating pyrolysis drum. The pyrolysis drum is an efficient mixing device and complete retorting of shale is achieved at about 480^{o}C (900^{o}F) during a short residence time. The shale oil vapors, the spent shale, and the ceramic balls exit together and are separated in an accumulator. The balls are lifted by an elevator and reheated in a ball heater, which is a direct contact heat exchanger designed to heat the balls to about 690^{o}C (1270^{o}F). Waste heat in the ball heater flue gases is transferred to the shale in the lift pipe preheat system. Spent shale exits from the accumulator vessel close to the retorting temperature of 480^{o}C (900^{o}F) and goes through a special heat exchanger designed to cool the spent shale and also generate steam for plant use. The spent shale is then cooled further by direct contact with water and moisturized for disposal. The shale oil vapor is quenched and then fractionated using conventional hydrocarbon processing equipment. An oil mist is not formed, so that no special separation equipment is needed.

Capital Costs(5) - $1.7 billion (1980 $); profile not available

Operating Costs Per Year(2) - (1979 $)

Gross - $111 million
Net - $ 97 million

Manpower Requirements(1)

See accompanying chart, Figure C-II

Operating Parameters

Input(2)		50,000 BPD	200,000 BPD
Oil Shale	-	66,000 TPD (34.8 GPT)	264,000 BPD
Raw Water	-	192,343 BPD (8,132 AF/Y)	769,372 BPD (32,528 AF/Y)
Electric Power	-	2,390 Mwh/D	9,560 Mwh/D
Output(2)			
Products			
Shale Oil	-	44,400 BPD	117,600 BPD
LPG	-	3,500 BPD	14,000 BPD
Sulfur	-	131 TPD	524 TPD
Ammonia	-	150 TPD	600 TPD
Coke	-	836 TPD	3,344 TPD
High Btu gas (958 Btu/SCF)	-	75,900,000 SCF/D	303,600,000 SCF/D
Water	-	14,143 BPD (598 AF/Y)	56,572 BPD (2,392 AF/Y)

Energy Efficiency[2,6] - (Millions of Btu)

$$\text{Net energy efficiency} = \frac{347{,}732 - 34{,}494}{347{,}732} = 90.1\%$$

1 BOE invested yields 10.1 BOE Products
1 BOE invested yields 7.5 BOE Liquids

$$\text{Thermal efficiency} = \frac{277{,}820}{34{,}494 + 317{,}177} = 79\%$$

Emissions[1] (Maximum)

SO_2	-	3.8 TPD	15.2 TPD
NO_x	-	20.9 TPD	83.6 TPD
THC	-	3.6 TPD	14.4 TPD
Particulates	-	3.1 TPD	12.4 TPD
CO	-	0.8 TPD	3.2 TPD

Solid Waste[1]

Spent Shale	-	53,200 TPD	212,800 TPD
Other	-	2,197 TPD	8,788 TPD

Source Documents

(1) Final Environmental Impact Statement - Proposed Development of Oil Shale Resource by The Colony Development Operation in Colorado.

(2) Oil Shale Data Book, June 1979.

(3) Energy Alternatives: A Comparative Analysis, Univ. of Oklahoma, May 1975.

(4) Colony PSD Permit, July 11, 1979.

(5) Colony Development Operation

(6) Engineering Calculations.

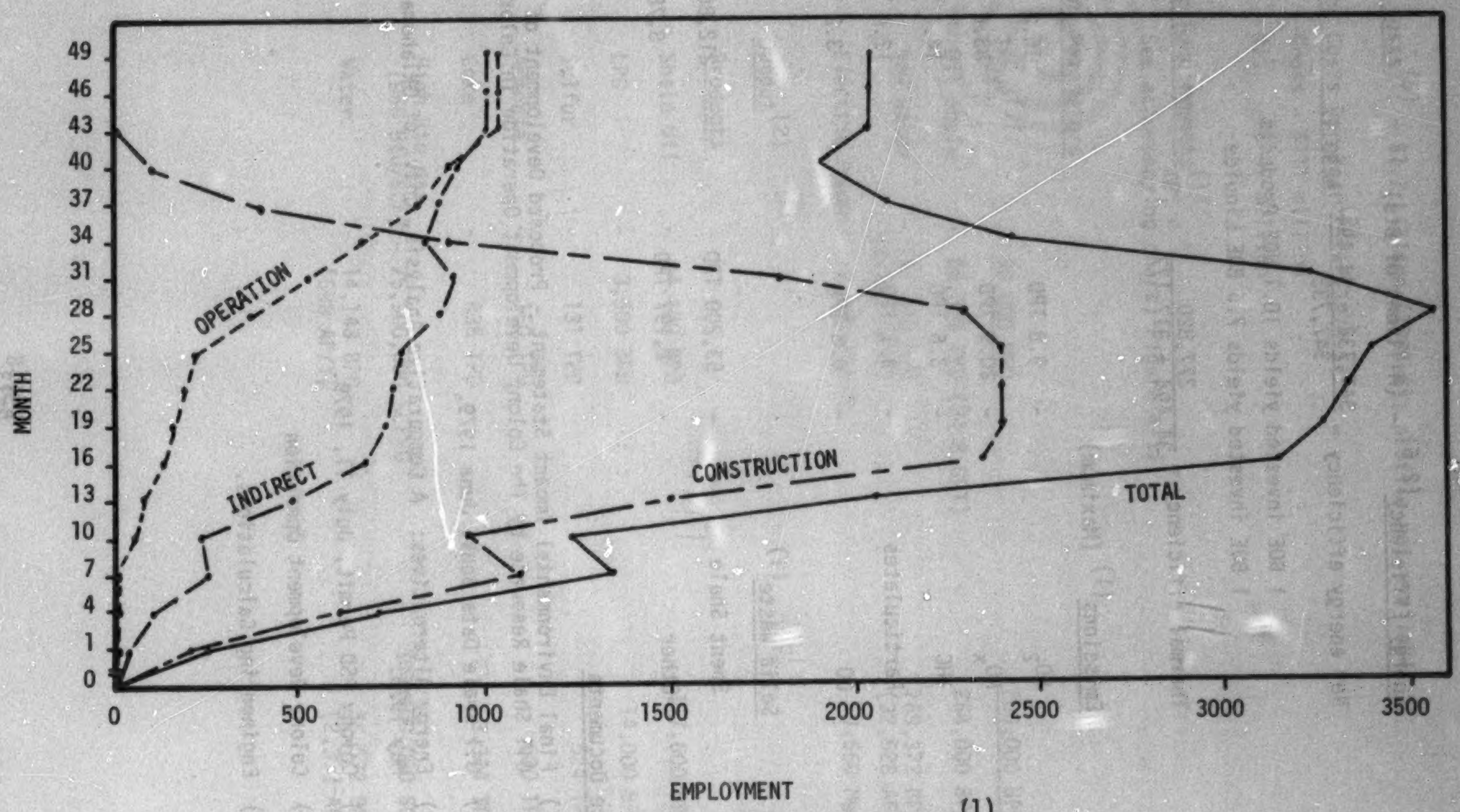

Figure B-II. Colony Related Employment(1)

B.4 Technology - Enhanced Oil Recovery

Process - Steam Injection

Location - Kern County, California

Steam drive (Steam Flood) - In this process, separate wells are utilized for injection and production. As in the steam soak process, a zone of hot oil, low-temperature steam, and hot water is generated ahead of the progressively expanding injected steam zone. This zone is moved toward nearby production wells by a combination of steam distillation of the oil, solvent extraction, gas drive, and waterflooding mechanisms. The first driving mechanism is due to partial oil vaporization and to decreases of the oil density and viscosity. The second mechanism is attributed to decreased oil surface tension overcoming rock pore capillary forces. The third mechanism is a result of dissolved gas expansion. Waterflooding occurs as steam cools and condenses into a zone of hot water flooding the formation toward the production wells.

Oil recovery efficiencies vary between 35 to 50 percent of the reservoir oil contacted by the steam drive. The energy input to the process is higher than that of the steam soak process because continuous steam generation is required. Consequently, the steam drive process produces more air pollution.

Capital Costs(2,5) - $378 million (1976 $) over 4 years

Operating Costs(2,5) - $79 million (1976 $)

Manpower Requirements -

550-600 peak construction
160-175 peak operations

Operating Parameters	50,000 BPD	200,000 BPD
INPUT		
Fuel Oil(1)	- 20,000 BPD	80,000 BPD
Water(4)	- 448,000 BPD (18,941 AF/Y)	1,792,000 BPD (75,764 AF/Y)
OUTPUT(4)		
Products	70,000 BPD (Gross)	280,000 BPD (Gross)
Heavy Oil	- 50,000 BPD (Net)	200,000 BPD (Net)
Usable Water	- 597,000 BPD (25,241 AF/Y)	2,388,000 BPD (100,962 AF/Y)

Energy Efficiency (from Appendix C)

Net Energy Efficiency = 95%

1 BOE Invested Yields 20.1 BOE Products

Emissions(3, 4, 5)	50,000 BPD	200,000 BPD
SO_2	- 5.0 TPD	19.8 TPD
NO_x	- 10.0 TPD	40.0 TPD
THC	- 0.1 TPD	0.4 TPD
Particulates	- 0.35 TPD	1.4 TPD
CO	- 0.1 TPD	0.4 TPD

Solid Wastes

Not Available

Source Documents

(1) Potential Environmental Consequences of Tertiary Oil Recovery, July 1976.

(2) Potential and Economics of Enhanced Oil Recovery - Update Report, November 1976.

(3) Environmental Impact Assessment: Enhanced Oil Recovery by Steamflood, Kern County, California, July 1978.

(4) The Water Requirements of Selected Enhanced Oil Recovery Processes, February 1979.

(5) Assumptions: 1100 production wells
1400 injection wells
All wells at 1500 ft. depth
Costs normalized to 1979
Emission Control Technology Efficiencies:

SO_2 - 95%
NO_x - 60%
Particulates - 95%

B.5 **Technology:** Outer Continental Shelf (OCS) Oil Production

Process: Platform

Location: Gulf of Mexico OCS

Process Description:

Conventional fixed platforms are used for most Gulf of Mexico OCS oil production. The platforms are typically steel jacketed structures which rest on the sea floor. From these platforms a number of wells are drilled. The well head completions are on the platform rather than the sea floor. Conventional platforms have been used in the Gulf in water depths up to 312 m (1025 ft.). The majority of oil production in the Gulf in the next 10 years will be from fixed platforms, rather than from subsea completions and floating platforms.

Oil, water, and natural gas produced from the wells are separated on the platform. The formation water is reinjected or disposed of. The oil is metered and piped to shore. Natural gas, if present, is dehydrated, pressurized, metered, and piped to shore. Offshore oil can be transported to shore by means of either tankers or pipelines. In the Gulf, pipelines are used almost exclusively. The pipelines are layed by barges and are usually buried in the sea floor to protect the pipelines from effects such as scouring, and to keep them from interfering with fishing.

Industry sources indicate that an average of 18,000 BPD are produced from a typical 35MM barrel recoverable reserve. A single 24-slot platform would be used to develop the field. Three exploratory wells and 18 development wells would be drilled to an average depth of 3600 m (12,000 ft.). Three such platforms would represent a 50,000 BPD case and 11 platforms would represent a 200,000 BPD case.

	50,000 BPD	200,000 BPD
Capital Costs:(2)	\$375 Million (1980 \$) Over one year	\$1,375 Billion (1980 \$) Over one year
Operating Costs:(2)	\$21 Million/year (1980 \$)	\$77 Million/year (1980 \$)
Manpower Profile:(2, 3)		
Development	152-167	570-625
Operation	32-44	119-163
Operating Parameters:(2)		
Outputs		
Oil	54,000 BPD	198,000 BPD
Gas	49×10^6 SCF/D	178×10^6 SCF/D
Water	32,000 BPD	120,000 BPD
Emissions(1)		
AIR (uncontrolled)		
SO_2	0.17 TPD	0.61 TPD
NO_x	2.75 TPD	10.1 TPD
CO	0.51 TPD	1.88 TPD
HC*	37.2 TPD	136.0 TPD
TSP	0.03 TPD	0.13 TPD
SOLID WASTES (1st year)(2)		
Drilling Mud	75,222 TONS	275,814 TONS
Drill Cuttings	38,632 YD^3	141,651 YD^3

Energy Efficiency (from Appendix C)

Net Energy Efficiency = 98.9%

1 BOE Invested Yields 87.9 BOE Products
1 BOE Invested Yields 75.9 BOE Liquids

*Methane comprises 90% of these emissions.

References

(1) Atmospheric Emissions From Offshore Oil and Gas Development and Production, EPA-450/3-77-026, June 1977.

(2) Industry supplied data

(3) Final EIS, Proposed Five Year OCS Oil and Gas Lease Sale Schedule, BLM, March 1980.

B.6 **Technology**: Coal Liquefaction

Process: SRC II

Location: Morgantown, West Virginia

Process Description

The primary processing sections consist of coal-slurry preparation, dissolver, refining, recycle gas treating and compression, and hydrogen recovery. Other sections include hydrogen production, gas plants, and secondary recovery systems. The plant is designed with utilities included except electric power, which is purchased from a local utility.

The feed coal is pulverized and mixed with a recycle slurry stream from the process and then is pumped, together with hydrogen, through a preheater to a dissolver operated at high pressure and temperature. The coal is first dissolved in the liquid portion of the recycle slurry, then is largely hydrocracked to liquids and gases.

The dissolver effluent is separated into gas, light hydrocarbon liquid, and slurry streams using conventional flashing and fractionation techniques. A portion of the mineral residue slurry and hydrocarbon liquid from the separation area is recycled to blend with the feed coal in the slurry preparation plant. The balance of the mineral residue slurry is vacuum-flashed to recover the fuel oil product.

The remaining dissolver area gas stream (consisting primarily of hydrogen, light hydrocarbons, and hydrogen sulfide) is washed with fractionated solvent to remove any entrained liquid hydrocarbons and contacted with diethanolamine (DEA) in an absorption system to remove acid gases. After acid gas removal the major portion of this gas is then recycled to the process. In order to maintain high hydrogen purity, however, the hydrogen gas is treated cryogenically to remove nitrogen, methane, and heavier hydrocarbon gases. The purified hydrogen stream is then combined with the untreated recycle hydrogen and recycled to the dissolver.

Liquid products from the main process area are refined in the fractionation section. The fractionation section separates the coal liquids into naphtha, light fuel oil and heavy fuel oil. Sour naphtha from the fractionation unit is desulfurized in a pressurized hydrodesulfurization unit. Sufficient severity is maintained in this unit to reduce the sulfur content to environmentally acceptable levels. (Some of the light fuel oil can be desulfurized in similar fashion, if required.)

Capital Costs (2) -$2,395 billion (1979 $)

Operating Costs (per year) (2) (1979 $) - (Fuel, operations and maintenance)

$486.4 million gross
$471.0 million net

Manpower Requirements (1)

Peak Construction - 7,089
Operations - 1,774

Operating Parameters (per day) (1)

Input	50,000 BPD	200,000 BPD
Coal (Pittsburgh No. 8) -	16,700 TPD	66,800 TPD
Water -	238,094 BPD (10,066 AF/Y)	952,376 BPD (40,264 AF/Y)
Electric Power -	2,840 Mwh/D	11,360 Mwh/D

Output		
"Fuel Oil" -	31,900 BPD	127,600 BPD
Naphtha -	7,300 BPD	29,200 BPD
LPG -	11,100 BPD	44,400 BPD
SNG (est) -	71.8 MM SCF/D	287.2 MM SCF/D
Sulfur -	445.3 TPD	1,781.2 TPD
Ammonia -	83.5 TPD	334 TPD

Energy Efficiency (from Appendix C)

Net Energy Efficiency = -49.4%

1 BOE Invested Yields 0.7 BOE Products
1 BOE Invested Yields 0.4 BOE Liquids

Emissions (1)	50,000 BPD	200,000 BPD
SO_2	- 4.5 TPD	18.0 TPD
NO_x	- 8.7 TPD	34.8 TPD
THC	- 0.5 TPD	2.0 TPD
Particulates	- 2.2 TPD	8.8 TPD
CO	- 0.7 TPD	2.8 TPD

Solid Wastes (1)		
Mine Burial	6,890 TPD	27,561 TPD
Tailings Point		
Landfill		

Source Documents

(1) Final Environmental Impact Statement, SRC II Demonstration Project, January 1981 (Scaled to 50,000 BPD and 200,000 BPD).

(2) Assessment of Process and Technology Requirements for Transportation Fuels, Final Report, October 1979.

B.7 **Technology:** Biomass/Alcohol

Process: Grain Fermentation

Location: Central Illinois

Process Description:

The reference case chosen for Biomass/Alcohol is an energy conserving plant design by R. Katzen Associates. The design incorporates traditional fermentation processes and demonstrated energy conservation processes, although no plant of this type has been built. The plant is designed to produce 50 MM gallons of 199° ethanol per year or 3,600 BPD from corn. Fourteen such plants would produce an average of 50,400 BPD of ethanol. To produce motor grade ethanol, the corn is milled, mixed with water to form a mash, and the mash is cooked at 350°F. The mash is cooled and the enzyme, fungal amylase, is added to the mash to change the starch to fermentable sugars. Yeast is added, and the mash ferments at a temperature of 95°F. The resultant beer contains 7.1 weight percent alcohol. The beer feed is heated and passed through a stripper/rectifier. Ethanol recovered is then dehydrated and cooled. The stillage residues are recovered, dried as Distiller's Dark Grains, and sold as an animal feed. The plant operates as a continuous flow process, except for the fermentation and fungal amylase sections which are operated batchwise to allow for frequent sterilization of the equipment. The distillation system employs a two-pressure concept which significantly improves its steam economy.

Capital Costs:

3,600 BPD plant: $58 million (1978 $) over a three-year time period
50,400 BPD Production:
(14 plants) : $812 million (1978 $)

Operating Costs:

3,600 BPD plant: $44.5 million (1978 $)
50,400 BPD production, (14 plants): 623 million (1978 $)

Operating Parameters: (plant operates 330 days/year)

Inputs (3)	3,600 BPD Plant	50,400 BPD Production (14 Plants)
Corn	58,990 bushels/day	825,860 bushels/day
Coal (Illinois No. 6)	296.7 tons/day	4,154 tons/day
Yeast	1.2 tons/day	17 tons/day
Denaturant (gasoline)	1,500 gals/day	21,000 gals/day
Anhydrous Ammonia	9.2 tons/day	129 tons/day
Make-up Hydrocarbon Solvent	27.4 gals/day	384 gals/day
Tractor Gasoline	864 gals/day	12,096 gals/day
Iodine Sterilizing Solution	24 gals/day	336 gals/day
Lime	2.4 tons/day	34 tons/day
Sodium Chloride	1.2 tons/day	17 tons/day
Sludge Polymer	48 lbs/day	672 lbs/day
Misc. BFW Treatment Chemicals	120 lbs/day	8,400 lbs/day

Outputs	3,600 BPD Plant	50,400 BPD Production (14 Plants)
Ethanol	3,608 BPD	50,512 BPD
Distiller Dark Grains	536.7 tons/day	7,514 tons/day
$(NH_4)_2 SO_4$	31.6 tons/day	442 tons/day

Utility Requirements (3, 4, 5)

Purchased Electric Power		
Connect (KW)	10,885 KW/D	152,390 KW/D
Operating (KW)	8,313 KW/D	116,382 KW/D
Make-up Water	253,000 GPD (256 acre-ft/yr)	3,542,000 GPD (3,584 acre-ft/yr)

Manpower Profile:

Construction: Unknown, but

$6.6 million of capital investment for a 3,600 BPD plant is for labor charges

3,600 BPD Plant

8 Technicians
43 Operators
54 Laborers
53½ Other (Administrative and Support)

158½ Total

50,400 BPD production (14 plants)

2,219 Total

Emissions (1,2,3,4,5)

Air

SO_2	7.3 TPD
Particulate	Negligible
CO_2	7,472 TPD
HC	NA
CO	NA
NO_x	NA
Waste Water	15.4×10^6 BPD
Solid Waste	594 TPD

Energy Efficiency (from Appendix C)

Net energy efficiency = - 8.7%

1 BOE Invested Yields 0.9 BOE Products

REFERENCES

(1) Compilation of air pollutant emission factors, EPA publication AP-42, August 1977.

(2) Assume emission control technology efficiencies of 95% for SO_2.

(3) Grain Motor Fuel Alcohol Technical and Economical Assessment Study, by R. Katzen Associates, June 1979.

(4) Energy Balances in the Production and End-Use of Alcohol Derived from Biomass and Coal, U.S. DOE and National Alcohol Fuels Commission, November 1979.

(5) Personal communication with Katzen Associates.

APPENDIX C

Energy Balances in the Production and Utilization of Fossil Fuels

1. ENERGY BALANCES IN THE PRODUCTION AND UTILIZATION OF OIL FROM SHALE

1.1 INTRODUCTION

Energy balances and net energy gains are presented for a reference facility producing oil from shale on the Naval Oil Shale Reserve 1 (NOSR), in Garfield County, Colorado.

The process specification, estimates, and calculations in this paper are based primarily on the Shale Oil Production System Reference Case Study (Reference 1) prepared by TRW, supplemented as appropriate with information from other sources. The reference case is a facility producing 50,250 barrels per day (BPD) of upgraded shale oil, comparable in quality and characteristics to sweet Indonesian or Libyan crude. The upgraded shale oil is very low in nitrogen and sulfur content, and can be substituted one-for-one for a premium imported crude oil as a refinery feedstock.

The reference case shown in Figure 1 calls for mining 73,700 tons per day (TPD) of oil-bearing shale. After primary and secondary crushing losses, 72,500 TPD of crushed shale are fed into the retorts. Seven direct-fired and two indirect-fired retorts, accepting lumps of shale 1/2"-3" in size, are used. Pieces smaller than 1/2" are processed in a fines retort.

The oil from the retorts is a viscous liquid containing nitrogen and sulfur, and is upgraded in a visbreaking unit and a hydrotreating unit. Sulfur and ammonia are obtained as byproducts in steps intended to prevent the emission of air pollutants. Spent shale from the retorts is disposed of as a compacted landfill in canyons near the facility. Figure 1 shows the steps involved in the production of oil from shale.

The materials and energy required as inputs from external sources to the NOSR 1 facility are shown in Figure 2. Inputs of electricity and water are the net requirements in excess of the amounts generated internally.

1.2 ENERGY BALANCE CALCULATIONS

The energy in fuels, electricity, and materials externally supplied to the NOSR 1 facility for producing 50,250 BPD of upgraded shale oil consists of the following:

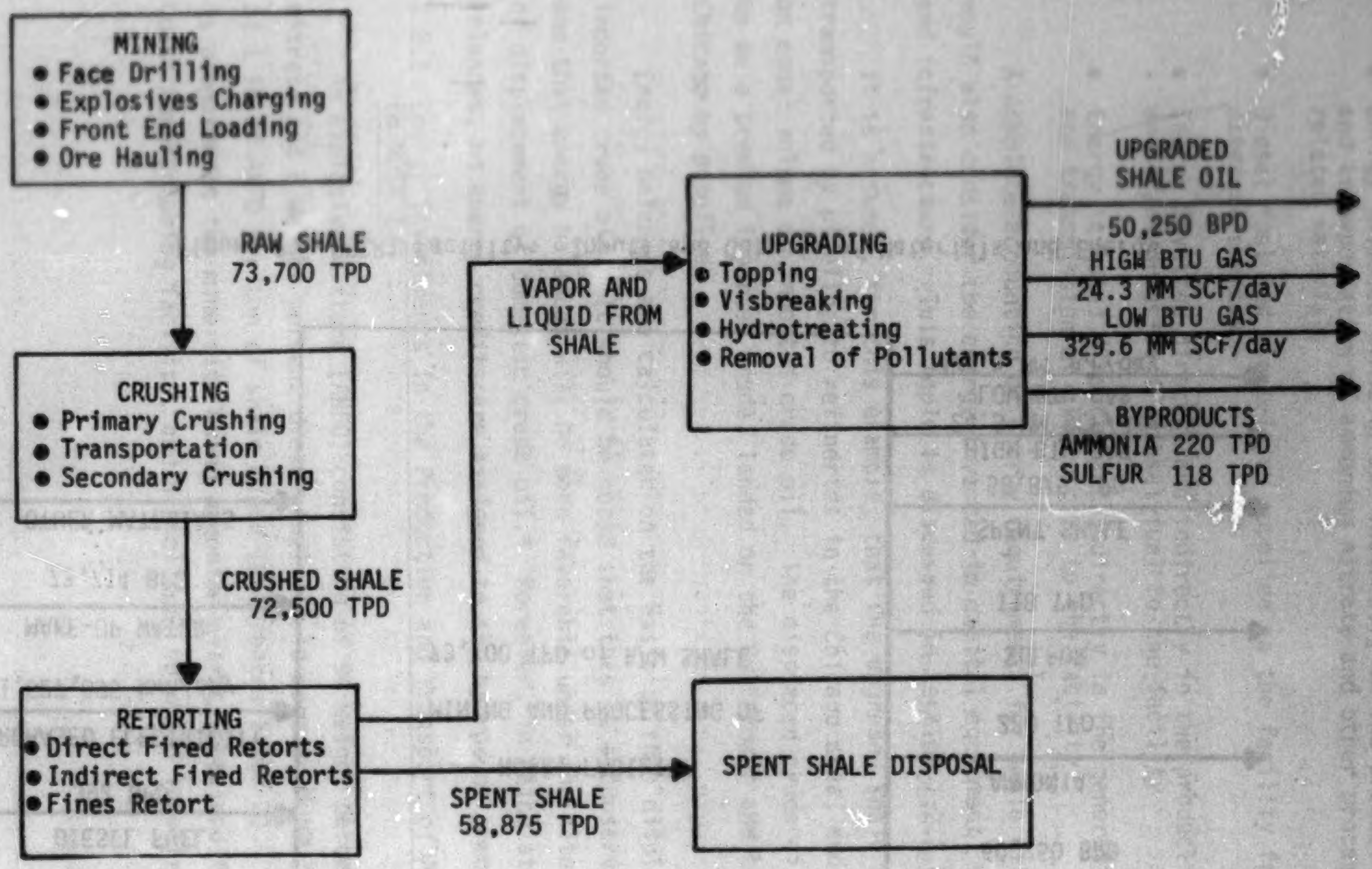
MINING
• Face Drilling
• Explosives Charging
• Front End Loading
• Ore Hauling
RAW SHALE
73,700 TPD
CRUSHING
• Primary Crushing
• Transportation
• Secondary Crushing
CRUSHED SHALE
72,500 TPD
RETORTING
• Direct Fired Retorts
• Indirect Fired Retorts
• Fines Retort
VAPOR AND
LIQUID FROM
SHALE
SPENT SHALE
58,875 TPD
UPGRADING
• Topping
• Visbreaking
• Hydrotreating
• Removal of Pollutants
SPENT SHALE DISPOSAL
UPGRADED
SHALE OIL
50,250 BPD
HIGH BTU GAS
24.3 MM SCF/day
LOW BTU GAS
329.6 MM SCF/day
BYPRODUCTS
AMMONIA 220 TPD
SULFUR 118 TPD

Figure 1. Steps in Shale Oil Production at NOSR1

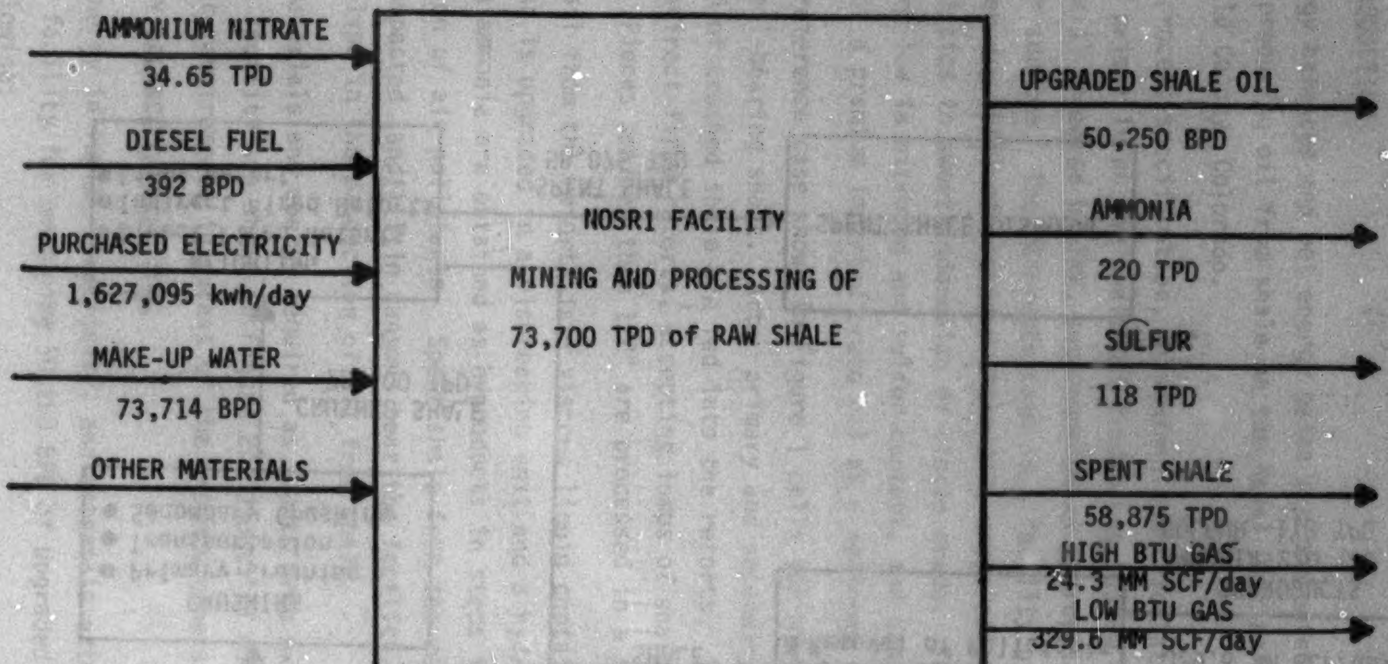
AMMONIUM NITRATE
34.65 TPD
DIESEL FUEL
392 BPD
PURCHASED ELECTRICITY
1,627,095 kwh/day
MAKE-UP WATER
73,714 BPD
OTHER MATERIALS
NOSR1 FACILITY
MINING AND PROCESSING OF
73,700 TPD of RAW SHALE
UPGRADED SHALE OIL
50,250 BPD
AMMONIA
220 TPD
SULFUR
118 TPD
SPENT SHALE
58,875 TPD
HIGH BTU GAS
24.3 MM SCF/day
LOW BTU GAS
329.6 MM SCF/day

Figure 2. NOSR1 Facility: Inputs and Outputs of Materials and Energy

- Energy invested directly and indirectly in the production and transportation of ammonium nitrate and other process-related materials
- Diesel fuel and electricity supplied to the facility from external sources
- Energy invested directly and indirectly in the production and transportation of diesel fuel to the facility
- Energy invested directly and indirectly in the generation and transmission of electricity to the facility

A complete accounting of energy requirements for shale oil production would also consider the energy invested in capital equipment, buildings, and infrastructure. This topic is discussed in Section 1.2.2.6.

It is assumed, for this example, that the upgraded shale oil will be transported by pipeline to refineries in the Chicago area, and will displace an equal volume of imported crude oil. The displaced crude oil is assumed to be a premium imported crude, landed on the Gulf Coast and transported to Chicago by pipeline.

Energy balances are calculated on the basis of this displacement of imported crude oil. It should be noted that this is a conservative assumption, and that energy balances will be more favorable under the alternative assumption of displacement of domestic crude oil.* Moreover, in calculating energy balances, no energy credits are assigned to the byproduct ammonia or sulfur.

1.2.1 Energy Investments in the Production and Transport of Ammonium Nitrate to NOSR 1

An explosive mixture (ANFO) consisting of 94 weight percent ammonium nitrate and 6 weight percent diesel fuel oil is used at NOSR 1 at the rate of 1 lb of ANFO per ton of shale mined (References 1 and 2). The ANFO mixture is prepared at the mine site using ammonium nitrate obtained from a Gulf Coast manufacturing facility, and diesel fuel obtained locally.

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* Energy invested in the extraction of domestic crude oil must be taken into account, whereas energy invested in imported crude oil is not drawn from U.S. resources.

Process steps in the manufacture and transport of ammonium nitrate to NOSR 1 are shown in Figure 3. Requirements for raw materials, fuels, and electricity in each step, corresponding to the 69, 278 lbs of NH_4NO_3 per day used at NOSR 1, have been calculated from information in Reference 4, and are summarized in Table 2.

Energy investments in the natural gas, diesel fuel, and electricity used to manufacture ammonium nitrate in the Gulf Coast area have been calculated on the basis of the following assumptions:

- Natural gas from wells in the Gulf Coast area is used
- Diesel fuel from a Gulf Coast refinery is used
- Primary fuels used for electricity generation reflect the generating mix for the Electric Reliability Council of Texas (ERCOT) region.

These energy investments are shown in Figure 4. Energy investments in electricity generation and transmission in the ERCOT region are shown in Figure 5. Energy investments in diesel fuel are negligible for the 143 gallons/day required to transport the ammonium nitrate to NOSR 1, and therefore are not reported.

Direct and indirect energy investments in the manufacture and transportation of 69,278 lb/day of ammonium nitrate are summarized in Table 3. Indirect investments are an order of magnitude smaller than direct investments. There is energy invested in the indirect investments, and energy invested to produce that energy, ad infinitum. In practice, energy imbedded in the indirect investments is two orders of magnitude smaller than the direct investments, and additional terms can be ignored except where recognizable as non-trivial by inspection.

1.2.2 Energy Investments in the Mining, Retorting, Upgrading, and Spent Shale Disposal Operations at NOSR 1

1.2.2.1 Diesel Fuel

Direct requirements for diesel fuel in the mining of 73,700 TPD of shale and in disposal of 58,875 TPD of spent shale are shown below:

Table 1. Daily Ammonium Nitrate (NH_4NO_3) Requirements at NOSR 1

Shale Mined = 73,700 TPD
ANFO Required = 73,700 lbs/day
NH_4NO_3 Required = 73,700 x 0.94 lbs/day
= 69,278 lbs/day
Diesel fuel Required for ANFO mixture = 4,422 lbs/day
= 614 gallons/day @ 7.2 lbs/gallon of diesel fuel (Reference 3)

Table 2. Energy Resource Requirements in the Manufacture and Transport of 69,278 lbs per day of Ammonium Nitrate

Resource Process Step	Natural Gas SCF/day	Electricity (Kwh/day)	Diesel Fuel (gallons/day)
Ammonia Manufacture	490,987	205	-
Nitric Acid Manufacture	-	251	-
Ammonium Nitrate Manufacture	-	1,386	-
Ammonium Nitrate Transport	-	-	143
Total	490,987[1]	1,842	143[2]

[1] Equivalent to 500.3 MMBtu @ 1,019 Btu/SCF
[2] Equivalent to 19.8 MMBtu @ 5.825 MMBtu/barrel
Conversion factors were obtained from Reference 4, p. 8-1.

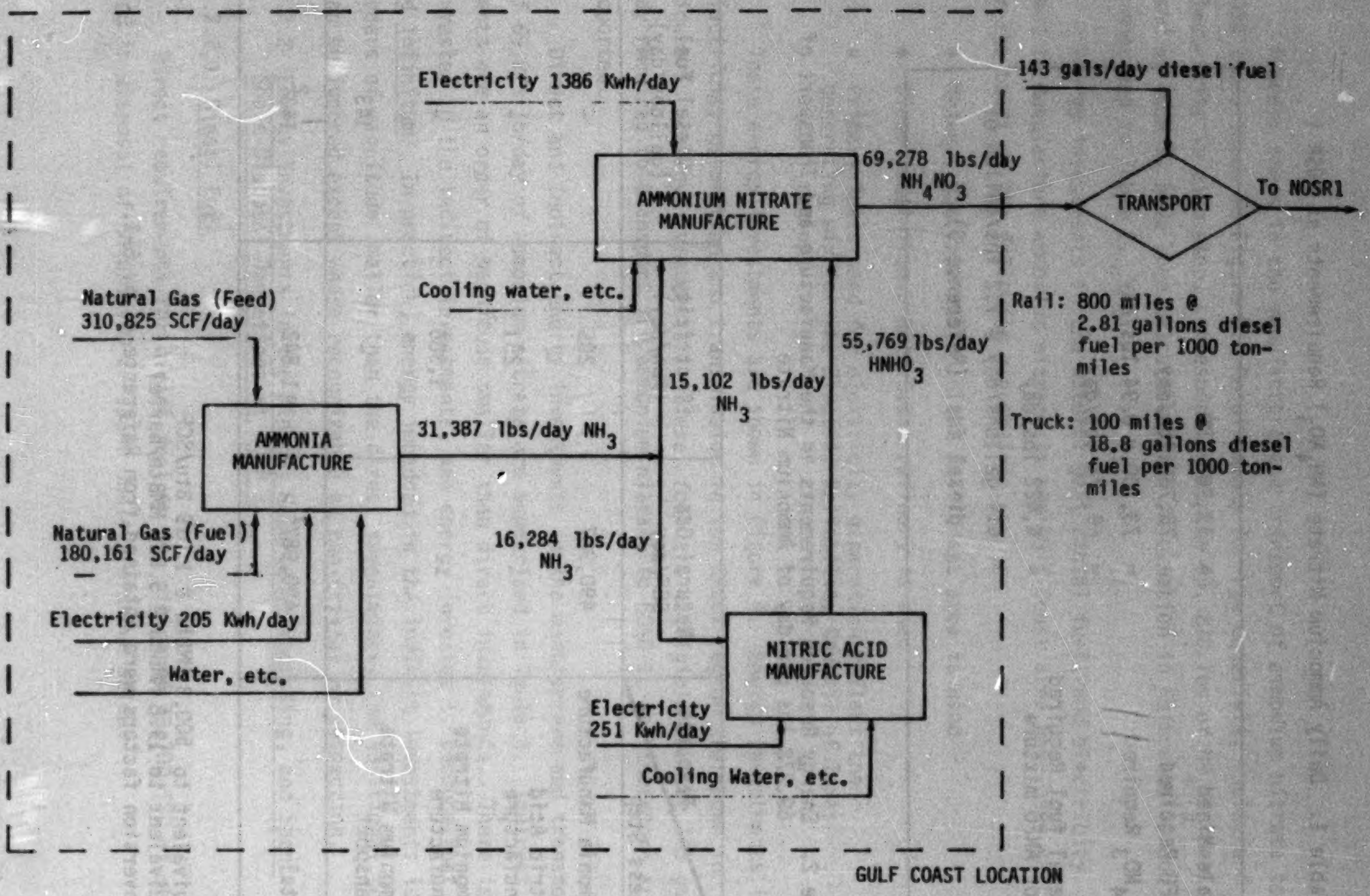
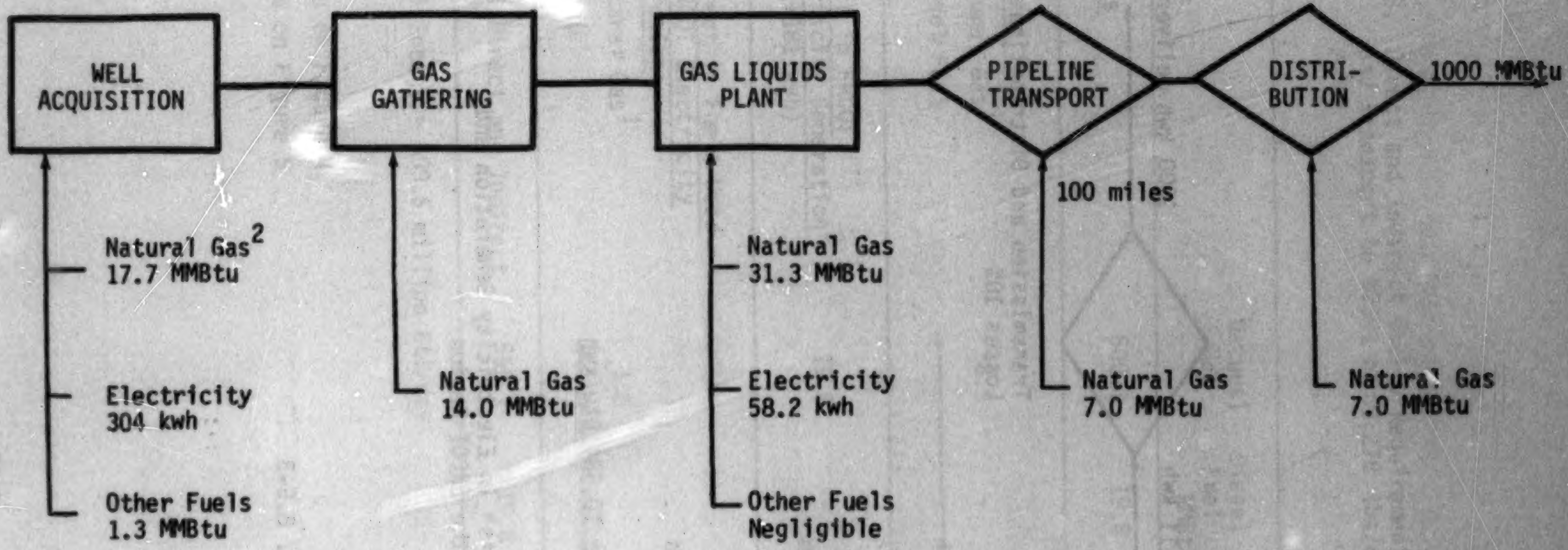

Electricity 1386 Kwh/day
143 gals/day diesel fuel
AMMONIUM NITRATE MANUFACTURE
69,278 lbs/day NH_4NO_3
TRANSPORT
To NOSR1
Cooling water, etc.
Natural Gas (Feed) 310,825 SCF/day
Rail: 800 miles @ 2.81 gallons diesel fuel per 1000 ton-miles
55,769 lbs/day $HNHO_3$
15,102 lbs/day NH_3
AMMONIA MANUFACTURE
31,387 lbs/day NH_3
Truck: 100 miles @ 18.8 gallons diesel fuel per 1000 ton-miles
Natural Gas (Fuel) 180,161 SCF/day
16,284 lbs/day NH_3
Electricity 205 Kwh/day
NITRIC ACID MANUFACTURE
Water, etc.
Electricity 251 Kwh/day
Cooling Water, etc.
GULF COAST LOCATION

Figure 3. Fuel and Electricity Required for the Manufacture and Transport of Ammonium Nitrate to NOSR1


WELL ACQUISITION
GAS GATHERING
GAS LIQUIDS PLANT
PIPELINE TRANSPORT
DISTRI-BUTION
1000 MMBtu
Natural Gas² 17.7 MMBtu
Electricity 304 kwh
Other Fuels 1.3 MMBtu
Natural Gas 14.0 MMBtu
Natural Gas 31.3 MMBtu
Electricity 58.2 kwh
Other Fuels Negligible
100 miles
Natural Gas 7.0 MMBtu
Natural Gas 7.0 MMBtu

Note: Energy invested in materials consumed for the entire cycle shown is = 30.1 MMBtu

Figure 4. Energy Investments[1] in the Production and Transport of Natural Gas in the Gulf Coast Area

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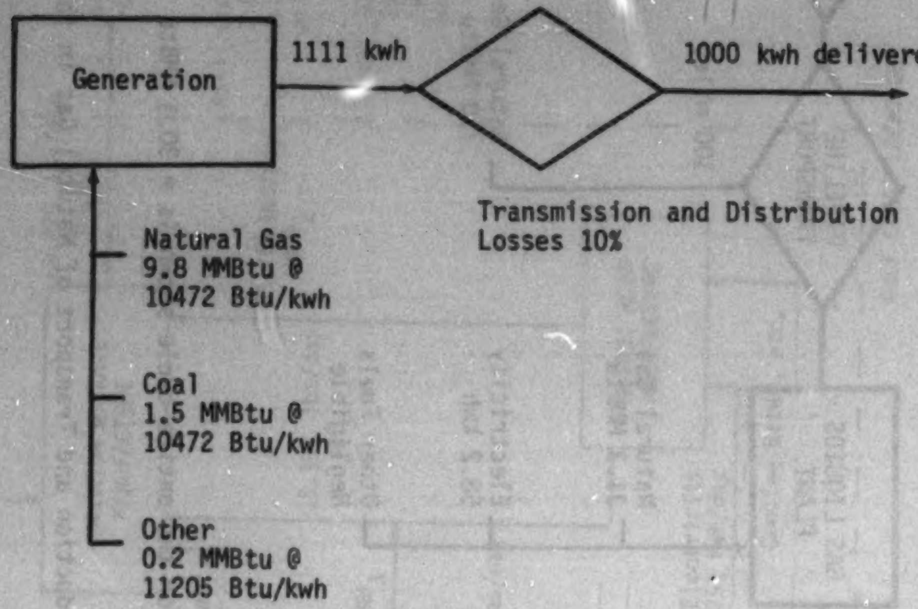
[1] Calculated using information from Reference 5, p. VI-20, VI-33 and II-8

[2] Includes natural gas recycled to process, but excludes physical loss of natural gas in extraction


Generation
1111 kwh
1000 kwh delivered
Transmission and Distribution Losses 10%
Natural Gas 9.8 MMBtu @ 10472 Btu/kwh
Coal 1.5 MMBtu @ 10472 Btu/kwh
Other 0.2 MMBtu @ 11205 Btu/kwh

Average = 10,484 Btu/kwh

Figure 5. Energy Investments* in Electricity Generation and Transmission in the ERCOT Region

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* Information from Reference 4, p. 8.5-3

Table 3. Direct and Indirect Energy Requirements in the Gulf Coast Manufactur
and Transport to NOSR1 of 69,278 lbs/day of Ammonium Nitrate

	Natural Gas	Diesel Fuel	Coal	Other	Electricity (kwh/day)
	MMBtu/day				
Direct	500.3	19.8	-	-	1842
Indirect in:					
Natural Gas[1]	38.5	-	-	15.7	181
Diesel Fuel	←	Negligible			→
Direct in ERCOT Electricity Generation[2] (1842+181 kwh)	19.8	-	3.0	0.4	
Indirect in Fuels Used in ERCOT Electricity Generation:					
Natural Gas[1]	1.5	-	-	0.6	
Coal	←	Negligible			→
Total Direct and Indirect	560.1	19.8	3.0	16.7	

Total Energy = 599.6 million Btu/day

[1] Based on Figure 4
[2] Based on Figure 5

- To operate mining equipment = 14,740 gallons/day @ 0.2 gallons/ton of shale mined (Reference 2, p. IV-2)
- For ANFO explosive mixture = 614 gallons/day (see Table 1)
- For transportation of spent shale to disposal site = 1,107 gallons/day

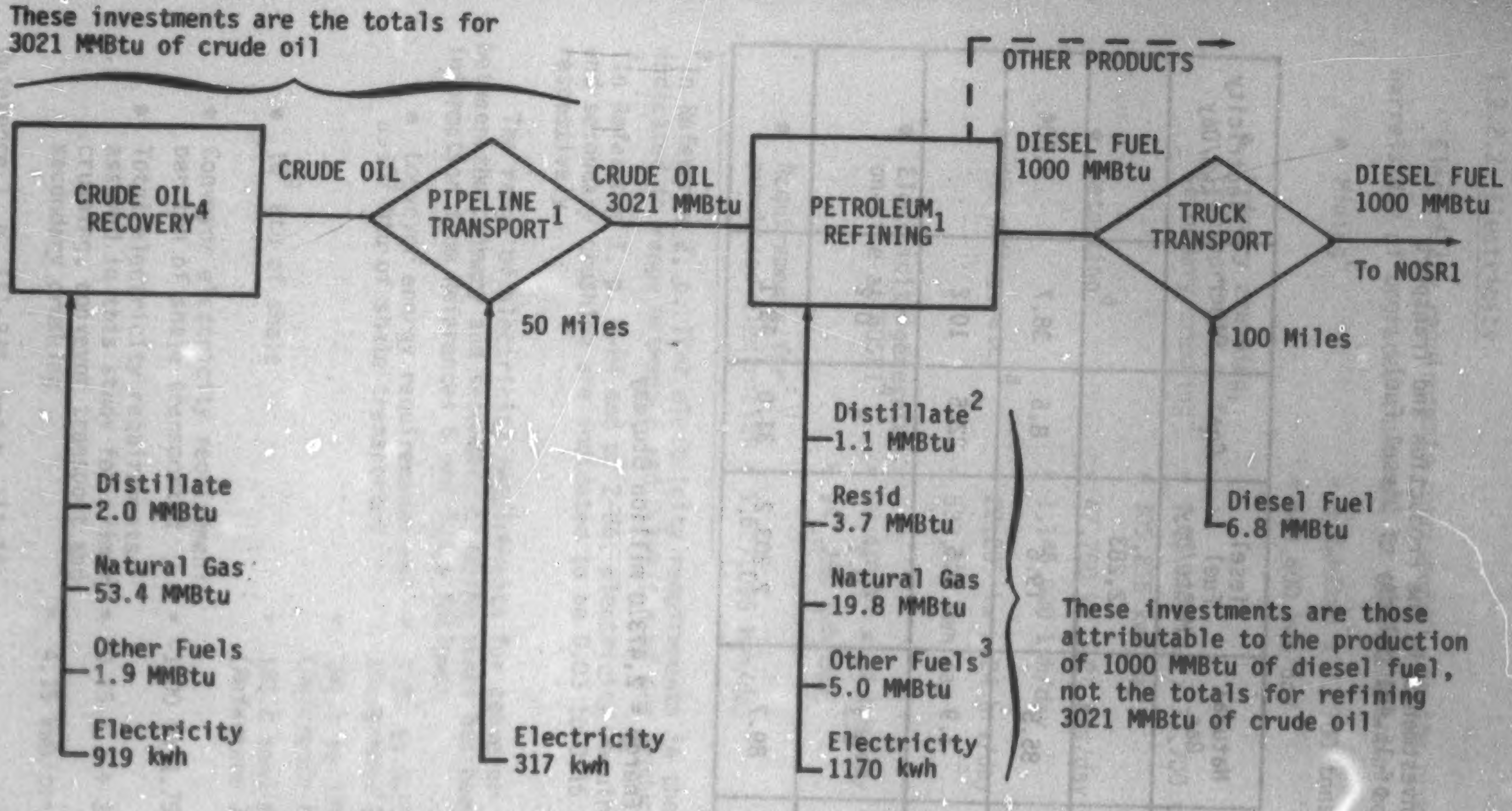
  (Calculated using a fuel consumption rate of 18.8 gallons of diesel fuel per 1,000 ton-miles for transportation by truck (Reference 4) and an assumed distance of one mile from the retorts to the disposal site.)
- Total direct requirement of diesel fuel = 16,461 gallons/day
  = 2,283 MMBtu/day @ 5.825 MMBtu/bbl

Energy investments in the production and transport of diesel fuel have been calculated using the following assumptions:

- Crude oil from the Colorado area is refined locally
- Diesel fuel from the local refinery is transported to the NOSR 1 facility by truck.

These investments are shown in Figure 6 on the basis of 1,000 MMBtu of diesel fuel delivered to NOSR 1. Investments in the refining step are those attributable to the production of distillate fuels (here treated as identical to diesel fuel). Investments in the crude oil recovery and transport steps correspond to the total refinery input of 3,021 MMBtu of crude oil. Of this, approximately one-third is attributable to the production of 1,000 MMBtu of distillate fuels (Reference 4, p. 8.1-2).

Direct and indirect energy investments in diesel fuel are summarized in Table 4. Investments of electricity are stated in kWh delivered. Translation to primary fuels will be accomplished after the total direct and indirect requirements for electricity at NOSR 1 are established.


These investments are the totals for 3021 MMBtu of crude oil
CRUDE OIL RECOVERY4
CRUDE OIL
PIPELINE TRANSPORT1
50 Miles
CRUDE OIL 3021 MMBtu
PETROLEUM REFINING1
OTHER PRODUCTS
DIESEL FUEL 1000 MMBtu
TRUCK TRANSPORT
100 Miles
DIESEL FUEL 1000 MMBtu
To NOSR1
Distillate 2.0 MMBtu
Natural Gas 53.4 MMBtu
Other Fuels 1.9 MMBtu
Electricity 919 kwh
Electricity 317 kwh
Distillate2 1.1 MMBtu
Resid 3.7 MMBtu
Natural Gas 19.8 MMBtu
Other Fuels3 5.0 MMBtu
Electricity 1170 kwh
Diesel Fuel 6.8 MMBtu
These investments are those attributable to the production of 1000 MMBtu of diesel fuel, not the totals for refining 3021 MMBtu of crude oil

Note: Energy invested in Materials = 34.2 MMBtu (crude oil recovery and transport steps)

Figure 6. Energy Investments in the Production and Transport of Diesel Fuel in the Colorado Area

---

[1] Calculated using information from Reference 4, p. 8.1-2

[2] Includes LPG

[3] Excludes refinery gases

[4] Calculated using information from Reference 5, p. VI-33 and II-8

Table 4. Energy Investments in the Production and Transport to NOSR1 of 16,461 gal/day of Diesel Fuel

	Natural Gas	Diesel Fuel MMBtu/Day	Coal	Other	Electricity kwh/Day
Direct Requirements		2,283			
Indirect in: Diesel Fuel	85.5	19.6	8.5	38.7	3,604
Direct in RMPA Electricity Generation	3.9	0.5	22.5	10.2	
Indirect in Fuels Used in RMPA Electricity Generation	0.3	0.1	-	0.2	
TOTALS	89.7	2,303.2	31.0	49.1	

Total Energy = 2,473.0 million Btu/day

1.2.2.2 Electricity

Electricity requirements corresponding to the production of 50,250 barrels/day of upgraded shale oil at NOSR1 are shown below.

- Mining[2] = 8 kwh/ton x 73,700 tons/day
  = 589,600 kwh/day
- Primary crushing, transport and secondary crushing[3] = 4.15 kwh/ton x 73,700 tons/day
  = 305,855 kwh/day
- Retorting[4] = 47,750 kw x 24 hrs/day
  = 1,146,000 kwh/day
- Upgrading, etc.[4] = 22,205 kw x 24 hrs/day
  = 532,920 kwh/day
- Electricity generated on-site at NOSR1[4] = 39,470 kw x 24 hrs/day
  = 947,280 kwh/day
- Requirements for purchased electricity = 1,627,095 kwh/day

The range of electricity requirements for conveyor transport of shale between the primary and secondary crushing steps has been calculated using information from References 6 and 7, as follows:

- Conveyor energy requirements per 10^9 Btu of shale transported = 1.95 to 3.25 MMBtu (Reference 6, p. 2-19, Section 2.5.2)
  = 191.1 to 318.4 kwh @ 10,206 Btu/kwh (Reference 6, p. 1-60, Table I-24)
- 10^9 Btu of shale = 181.8 tons @ 2,750 Btu/lb of shale (Reference 7, p. 50)
- Conveyor electricity requirements per ton of shale transported = ~1.00 to 1.75 kwh
- Total electricity requirements assumed in this study for primary crushing, conveyor transport and secondary crushing = 0.15 + 1 + 3
  = 4.15 kwh/ton

---

[2] In Reference 2, p. IV-2 electricity requirements in the mining step are indicated to range between 6 and 8 kwh/ton of ore produced.

[3] In Reference 1, p. 2-84 and p. 2-86, electricity requirements for primary and secondary crushing are indicated to be 0.03 to 0.15 kwh/ton and 2 to 3 kwh/ton, respectively.

[4] Reference 1, p. III-3/4, and p. III-11.

1.2.2.3 Electricity Requirements in the Transport of Upgraded Shale Oil to Final Markets

The upgraded shale oil is transported via a feeder pipeline to a trunk pipeline through which it is sent to a refinery in the Chicago area. Energy requirements for transportation are:

- Feeder Pipeline

  Distance = 10 miles (Reference 8)
  Electricity Required[5] = 6,120 kwh/day

- Trunk Pipeline

  Distance = 1,000 miles (Reference 8)
  Electricity Required[5] = 612,000 kwh/day

1.2.2.4 Energy Investments in Purchased Electricity Used at NOSR 1

The following requirements for purchased electricity at the NOSR1 facility are assumed to be met using power generated in the Rocky Mountain Power Area (RMPA):

(a)	Purchased electricity for NOSR1 facility	1,627,095 kwh
(b)	Electricity for feeder pipeline	6,120 kwh
	Total	1,633,215 kwh

The mix of primary resources for electricity generation in RMPA, which is a subregion of the Western Systems Coordinating Council (WSCC), is shown in Table 5. Energy requirements for electricity generation, assuming that 10 percent of the generated electricity is lost in transmission, are shown in Table 6. The electricity requirements for transporting 50,250 BPD of upgraded shale oil through the trunk pipeline to Chicago are not included, the reason for which is explained in Section 1.2.3.

---

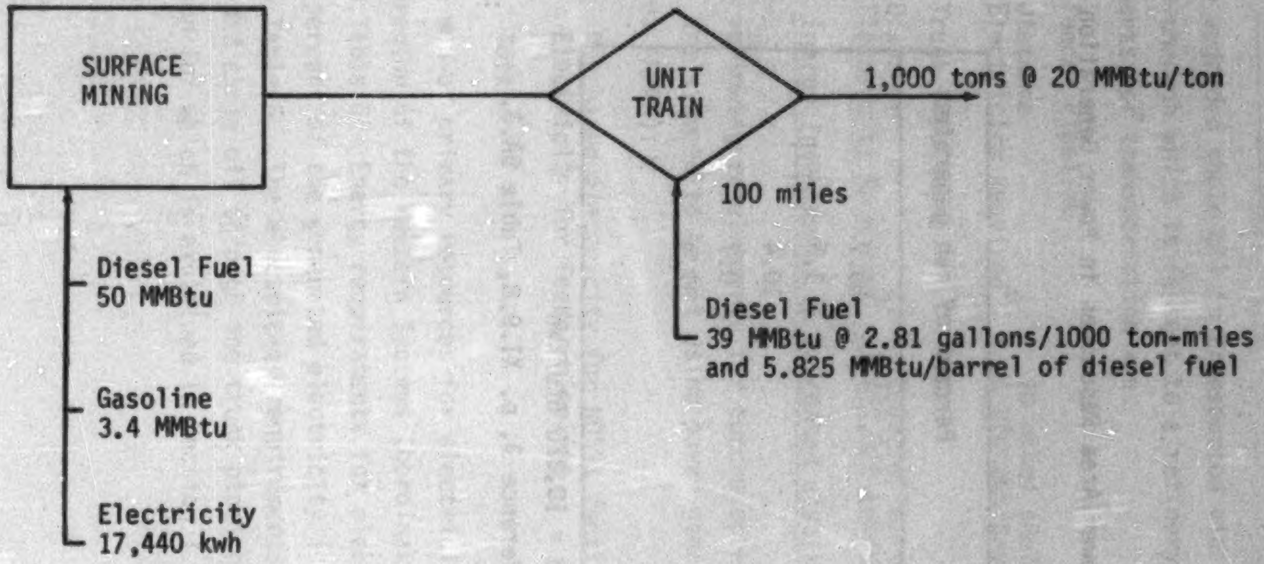
[5] Based on 2.1 kwh per 1,000 MMBtu-mile (Reference 5, p. VI-42) and 5.8 MMBtu/barrel of upgraded shale oil (Reference 6, p. 2-33, and p. 2-47; Reference 7, p. 51).

Table 5. Rocky Mountain Power Area Resources in Power Generation (1979)

Resources	Percent of kwh generated
Coal	59.7
Distillate	1.3
Natural Gas	10.4
Nuclear	0.7
Hydro	27.9

Average = 10,326 Btu/kwh

Based on information in Reference 9, p. XI.9.8, Table 9A.3.


SURFACE MINING
UNIT TRAIN
1,000 tons @ 20 MMBtu/ton
100 miles
Diesel Fuel
50 MMBtu
Gasoline
3.4 MMBtu
Electricity
17,440 kwh
Diesel Fuel
39 MMBtu @ 2.81 gallons/1000 ton-miles
and 5.825 MMBtu/barrel of diesel fuel

Note: Energy invested in materials consumed = 48.4 MMBtu

Figure 7. Energy Investments[1] in the Production and Transport of Coal in the Colorado Area

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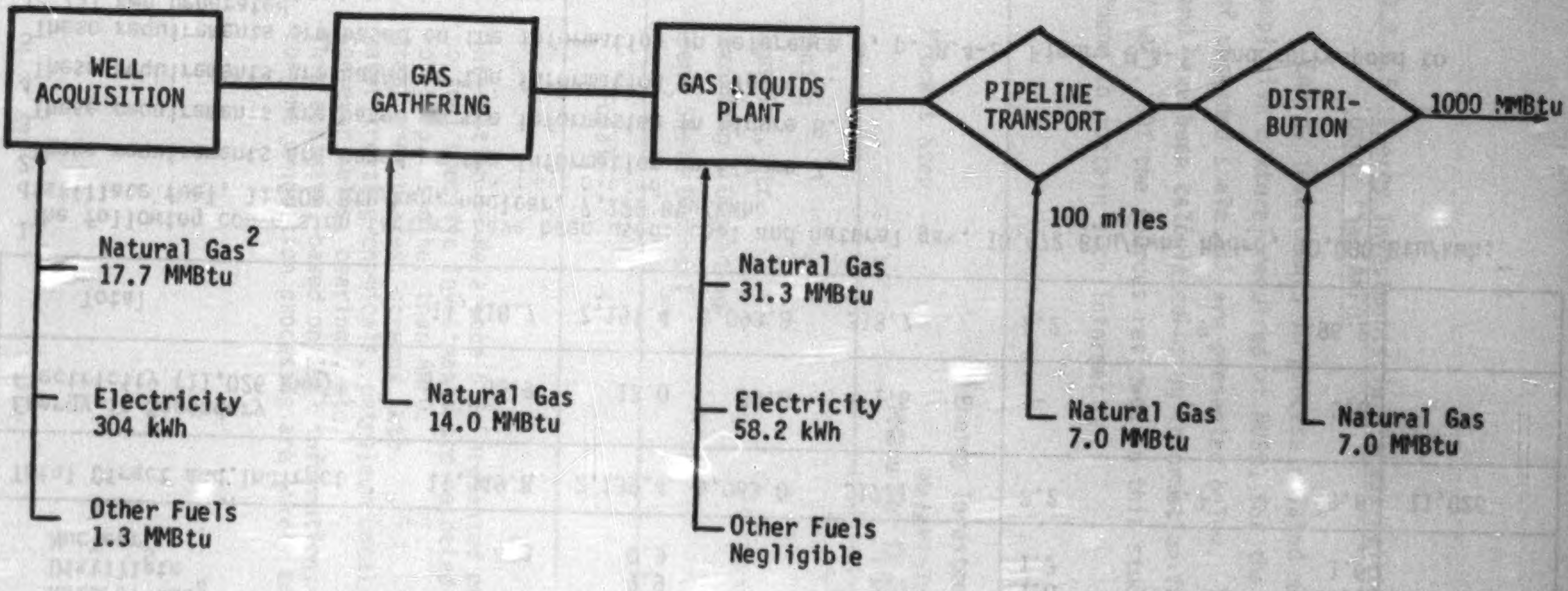
[1] Calculated using information from Reference 5, p. VI-8 and VI-2.


WELL ACQUISITION
GAS GATHERING
GAS LIQUIDS PLANT
PIPELINE TRANSPORT
DISTRI-BUTION
1000 MMBtu
Natural Gas[2] 17.7 MMBtu
Electricity 304 kWh
Other Fuels 1.3 MMBtu
Natural Gas 14.0 MMBtu
Natural Gas 31.3 MMBtu
Electricity 58.2 kWh
Other Fuels Negligible
100 miles
Natural Gas 7.0 MMBtu
Natural Gas 7.0 MMBtu

Note: Energy invested in materials consumed for the entire cycle shown is = 30.1 MMBtu

Figure 8. Energy Investments[1] in the Production and Transport of Natural Gas in the Colorado Area

---

[1] Calculated using information from Reference 5, p. VI-20, VI-33 and II-8

[2] Includes natural gas recycled to process, but excludes physical loss of natural gas in extraction

Table 6. Energy Requirements for Generating 1,814,683 kWh in RMPA

	Coal	Natural Gas	Hydro	Distillate	Residual Fuel	Gasoline	Other	Electricity (kwh)
				(MMBtu)				
Direct in Electricity Generation[1]	11,345.0	1,976.4	5,063.0	264.3	-	-	-	
Indirect in								
Coal[2]	-	-	-	50.5	-	1.9	27.4	9,893
Natural Gas[3]	-	152.2	-	-	-	-	62.1	716
Distillate[4]	-	9.9	-	2.3	1.0	-	4.5	417
Nuclear[5]	4.8	0.9	-	-	1.2	-	1.6	
Total Direct and Indirect	11,349.8	2,139.4	5,063.0	317.1	2.2	1.9	95.6	11,026
Energy in Secondary Electricity (11,026 kWh)	68.9	12.0	30.8	1.6	-	-	0.6	
Total	11,418.7	2,151.4	5,093.8	318.7	2.2	1.9	96.2	

[1] The following conversion factors have been used: coal and natural gas, 10,472 Btu/kwh; hydro, 10,000 Btu/kwh; distillate fuel, 11,205 Btu/kwh, nuclear, 7,129 Btu/kWh.

[2] These requirements are based on the information in Figure 7.

[3] These requirements are based on the information in Figure 8.

[4] These requirements are based on the information in Figure 6.

[5] These requirements are based on the information in Reference 4, p. 8.4-2, Figure 8.4-1, and correspond to 12,731 kwh generated.

Total Energy = 19,082.9 million Btu/day

1.2.2.5 Energy Investments in Process-Related Materials Used at NOSR 1 Other than ANFO

Energy investments in process related materials (other than the ANFO explosive mixture) required at NOSR1 for the production of 50,250 barrels of upgraded shale oil are presented below. These investments are approximate, and have been calculated using information from Reference 5(p. VI-75 through VI-81). Of the sources reviewed in this study only Reference 5 has been found to contain such information.

Process Step	Energy Investments in Process Related Materials[1] (supplies) (MMBtu per 50,250 barrels of shale oil)
Mining	891[2]
Crushing, etc.	1,709[3]
Retorting & Upgrading	5,550[4]
Spent Shale Disposal	339[5]
Total	8,489[6]

1. Information in Reference 5 is presented only in total Btu terms, i.e., no fuel specific investments are reported for supplies.
2. For supplies other than ANFO.
3. Steel wear plates, screens, etc.
4. Water treating chemicals, petroleum catalysts, activated carbon, etc.
5. Conveyor belts, bearings, etc.
6. This estimate, based on 1967 information, is conservative because current production processes are likely to be less energy intensive.

1.2.2.6 Energy Investments in Equipment, Buildings, and Infrastructure

Equipment

Energy investments in capital equipment in the NOSR1 facility have been calculated on the basis of information in Reference 5, p. VI-75 through VI-81. These investments, prorated to one day's production of 50,250 barrels of upgraded shale oil, are shown in Table 7.

These energy investments in equipment are approximate. They are calculated in Reference 5 on the basis of so many Btu per dollar of capital expenditure, rather than by analyzing the materials and processes used to produce the equipment.

Table 7. Energy Investments in Capital Equipment

Process Step	Energy Investments in Capital Equipment (MMBtu per 50,250 barrels of shale oil)
Mining	N/A
Crushing[1]	210
Retorting and Upgrading[2]	1,766
Spent Shale Disposal[3]	304
Total	2,280

[1] Gyratory crushers, storage bins, ore feeders, impact crushers, screens, bag filters, blowers, etc.

[2] Retorts and upgrading equipment.

[3] Conveyors, trucks, compactors, bulldozers, etc.

Buildings

Energy investments in buildings in the NOSR1 facility are estimated below. The areas of buildings in the NOSR1 facility are given in Reference 1:

Building	Square Feet
Control House	15,000
Administration	15,000
Laboratory	6,000
Operations	15,000
Guard, Fire, and First Aid	4,700
Warehouse, Shops, and Vehicle Maintenance	57,000
Total	112,700

An average energy investment of 970,000 Btu per square foot is reported for new industrial buildings in Reference 10, page 840, Table 2. On this basis, the energy invested in the buildings is:

112,700 sq ft x 970,000 Btu/sq ft, or 109,319 MMBtu.

Prorating this investment over 30 years, the energy investment corresponding to one day's production of 50,250 barrels of shale oil is:

109,319 MMBtu/30 x 365 or 9.98 MMBtu (~ 10 MMBtu).

This is a very small number relative to the direct and indirect energy supplied to the process.

Industrial Infrastructure

Energy investments in industrial infrastructure are difficult to estimate, even when site-specific information is available. The construction of major highways and pipelines are examples of industrial infrastructure. It is necessary to resolve whether the provision of such infrastructure is uniquely associated with the project under review. If several projects are under development in that area, it is necessary to resolve how the energy investments in the infrastructure should be allocated among these projects.

Residential and Community Infrastructure

Houses, schools, hospitals, and municipal services must be provided for workers involved in plant construction and operation. Planning and capital investment for the construction of houses and institutions are proper areas of concern for state and local government. However, the energy invested in such construction should not be included in energy balance calculations. From the perspective of the national economy, if these workers were not employed at this location, presumably they would be employed at other locations in the United States, where they would demand a comparable number of houses, schools, etc. The national economy must provide for the needs of these workers whether or not a shale oil production facility is built in NOSR1.

1.2.3 Energy Investments in Electricity for Trunk Pipeline

The trunk pipeline traverses several NERC regions as it proceeds from the NOSR1 area via Casper, Wyoming to Chicago. The simplifying assumption is made that the electricity for pumping is generated from coal. A more exact treatment, identifying the pumping stations and the electricity generating mix appropriate to each pumping station, is beyond the scope of the present study.

Direct and indirect energy investments in electricity for the trunk pipeline, assuming that 10 percent of the electricity generated is lost in transmission, are shown in Table 8.

Table 8. Energy Requirements for Generating 680,000 kwh

	Coal	Distillate Fuel	Gasoline	Other	Electricity
	(MMBtu)				(kwh)
Direct in Electricity Generation 1/	7121	-	-	-	
Indirect in Coal 2/		31.7	1.2	17.2	6210
Total Direct and Indirect	7121	31.7	1.2	17.2	6210
Energy in Secondary Electricity (6210 kwh)	65	0.3	-	0.2	
Total	7186	32	1.2	17.4	

Total Energy Invested = 7,236.6 million Btu/day

[1] Based on a conversion factor of 10,472 Btu per kwh

[2] Based on Figure 7 and the assumption that energy investments in coal production and transportation are similar in regions traversed by the pipeline

The upgraded shale oil is assumed to displace imported crude oil of a comparable quality on a barrel-per-barrel basis. For markets in the Chicago area, the energy savings that can be ascribed to the 50,250 barrels of shale oil produced at NOSR 1, corresponds to the energy in an equivalent amount of imported crude oil (at 5.8 MMBtu/barrel) less the direct and indirect energy invested in transporting that crude to the Chicago area from a Gulf Coast port. Energy investments in the transport by pipeline of imported crude oil are shown in Table 9. These have been calculated on the assumption that the electricity required for the pipeline is generated from coal electric plants located in the four state region traversed by the pipeline (Texas, Oklahoma, Missouri, and Illinois). This is a conservative assumption. The use of any premium fuels in the generating mix for electricity to transport the imported crude oil would result in an equivalent saving of premium fuels attributable to the displacement of imported crude oil by shale oil.

Table 9. Direct and Indirect Energy Investments in the Transport of 50,250 Barrels of Imported Crude Oil From the Gulf Coast Area to Chicago

Electricity requirements at 2.1 kwh/1,000 MMBtu-mile and 1,000 miles of transport	=	612,000 kwh
Direct fuel (coal) requirements for electricity generation[1]	=	7,121 MMBtu
Indirect energy invested in the coal[2]	=	148 MMBtu
Total	=	7,269 MMBtu

---

[1] Assuming 10 percent of the electricity generated is lost in transmission and a conversion factor of 10,472 Btu/kwh.

[2] Assumed similar to that shown in Table 7.

1.2.4 Summary

Table 10. Direct, Indirect, and Total External Energy Investments in the Production and Transport of Shale Oil From NOSR1

MMBtu per 50,250 barrels of upgraded shale oil

	Petroleum Fuels	Premium Fuels (Petroleum Fuels & Natural Gas)	All Energy Resources (Including Premium Fuels)
DIRECT			
• For diesel fuel at NOSR1 facility for: - Operations of mining equipment - Explosive mixture (ANFO) - Disposal of spent shale	2,283	2,283	2,283
• Central Station electricity generated in the Rocky Mountain power area	324	2,483	19,139
• Energy invested in the ammonium nitrate and other process-related materials delivered to NOSR1	20	580	9,089
INDIRECT			
• Energy invested in capital equipment (prorated to one day's production at NOSR1)	N/A	N/A	2,280
• Energy invested in the buildings at NOSR1 (prorated to one day's production at NOSR1)	N/A	N/A	10
• Fuels used in the recovery, transport, and refining of crude, attributable to the diesel fuel delivered to NOSR1	29	115	154

(Continued)

Table 10. Direct, Indirect, and Total External Energy Investments in the Production and Transport of Shale Oil From NOSR1 (Continued)

MMBtu per 50,250 barrels of upgraded shale oil

	Petroleum Fuels	Premium Fuels (Petroleum Fuels & Natural Gas)	All Energy Resources (Including Premium Fuels)
Total Direct Energy Investment	2,627	5,346	30,511
Total Indirect Energy Investment	29	115	2,444
Total of External Energy Investments	2,656	5,461	32,955

Total Recoverable Energy From NOSR1 Plant = 339,462 MMBtu/day

1 bbl energy invested yields 10.3 bbls energy products.

1 bbl energy invested yields 8.8 bbls liquid products.

$$\text{Net Energy Efficiency} = \frac{339{,}462 - 32{,}955 \times 100}{339{,}462} = 90.3\%$$

1.3 REFERENCES

1. "Shale Oil Production System Reference Case Study," TRW Final Report, June 1979. Prepared for the U.S. Department of Energy, Naval Oil Shale Reserves Pre-development Project.

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3. Gary, J. H., and Handwerk, G. E., Petroleum Refining: Technology and Economics, Chemical Processing and Engineering Series, Volume 5, Marcel Dekker Inc., New York, 1975

4. Balasubramaniam, M., Standley, W., et al, "Energy Balances in the Production and Use of Alcohols Derived From Biomass and Coal," TRW Document No. 97611-E001-RU-00, November 1979. Prepared for the U.S. Department of Energy and the National Alcohol Fuels Commission.

5. "Net Energy Analysis: An Energy Balance Study of Fossil Fuel Resources," Colorado Energy Research Institute Report, April 1976

6. "Energy Alternatives: A Comparative Analysis," Report Prepared by the Science and Public Policy Program, University of Oklahoma, Norman, Oklahoma, May 1975

7. McKee, J. M., and Kunchal, S. K., "Energy and Water Requirements for an Oil Shale Plant Based on Paraho Processes," Quarterly of the Colorado School of Mines, Proceedings of the Ninth Oil Shale Symposium, Vol. 71, No. 4, October 1976

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2. ENERGY BALANCES OF SOLVENT REFINED COAL (SRC-II)

Direct liquefaction of coal to produce liquid fuels is one alternative to development of the NOSR. In 1974, a 50-ton per day (TPD) SRC pilot plant was placed in operation at Ft. Lewis, Washington, and a 6,700 TPD SRC-II demonstration plant was designed for possible siting at Morgantown, West Virginia. Since Morgantown is considered to be a potential area for construction of the first direct coal liquefaction demonstration plant, it was selected as the geographic area for a SRC-II energy analysis (Reference 1).

The principal data source for the SRC-II analysis is the Phase Zero task report, dated 31 July 1979, of the SRC-II Demonstration Project for DOE (Pittsburgh & Midway Coal Mining Company). The major stages of SRC-II liquefaction are coal slurry preparation, dissolving, refining, recycle gas heating and compression, and hydrogen recovery. The battery-limits plant also includes an integrated hydrogen production facility and a secondary recovery and oxygen plant. The product slate for SRC-II includes low-sulfur fuel oil (equivalent to utility and industrial fuel oil), pipeline-quality gas, naphtha (350^{o}F EP), a light hydrocarbon stream (ethane/propane), and a butane stream.

2.1 DIRECT ENERGY INPUTS TO SRC-II

Figure 2-1 illustrates the direct energy-related inputs to SRC-II for the production of 1,000 MMBtu of low-sulfur fuel oil. These values were derived by scaling the balances for the 33,500 TPD commercial-scale plant. Coal is both a process feedstock and the primary plant energy source. Purchased electricity amounts to only 0.3 percent of the energy resources consumed by the plant.

2.2 INDIRECT ENERGY REQUIREMENTS FOR SRC-II

Coal Mining. Coal is the primary feedstock and energy source for SRC-II. For purposes of this study, it is assumed: that the SRC-II plant is located within five miles of the coal source; that underground mining of high-sulfur bituminous coal is employed; that run-of-mine (ROM) coal is given a very rough cleaning at a mine-mouth facility; and that coal is transported to the SRC-II plant via unit train. It is assumed that coal will be purchased as the requirement for the plant is 11 million tons/year and the largest underground mine, Consolidation's Ireland mine produces only 2.6 million tons/year.

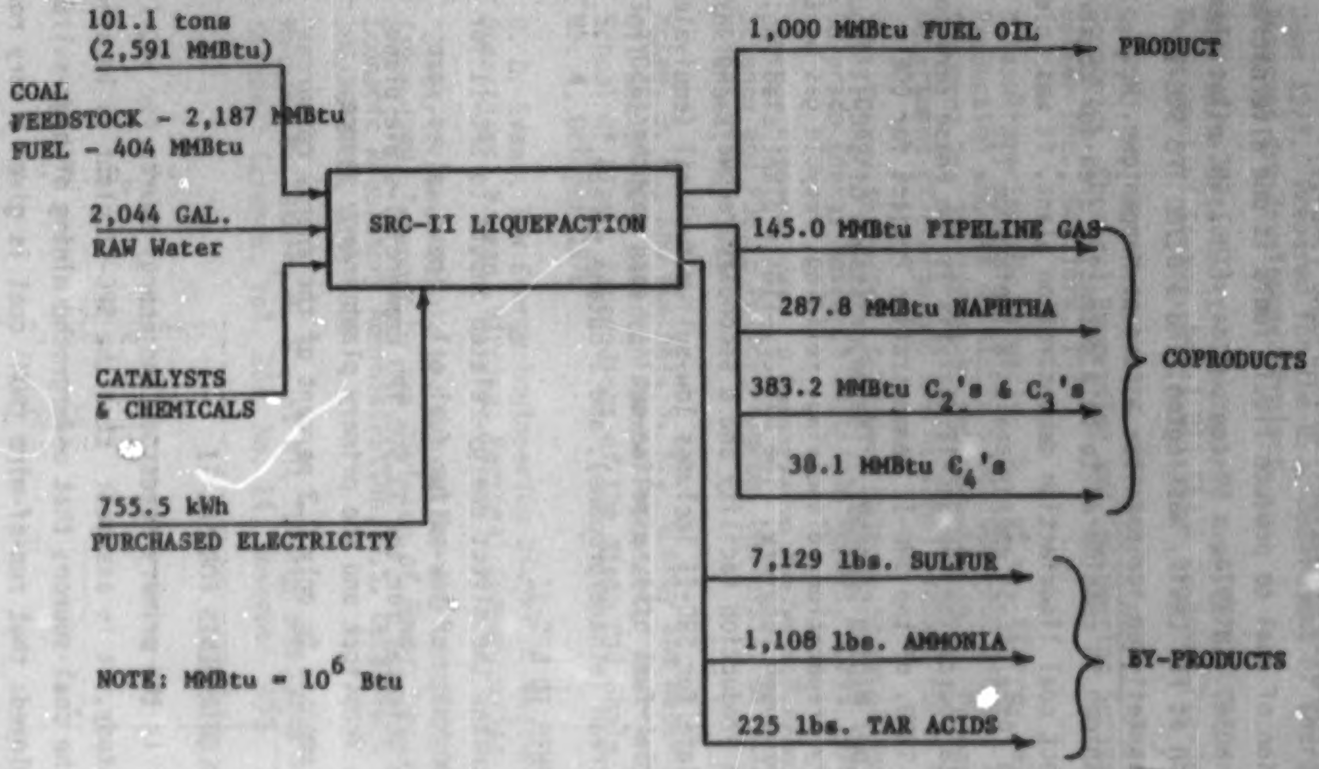
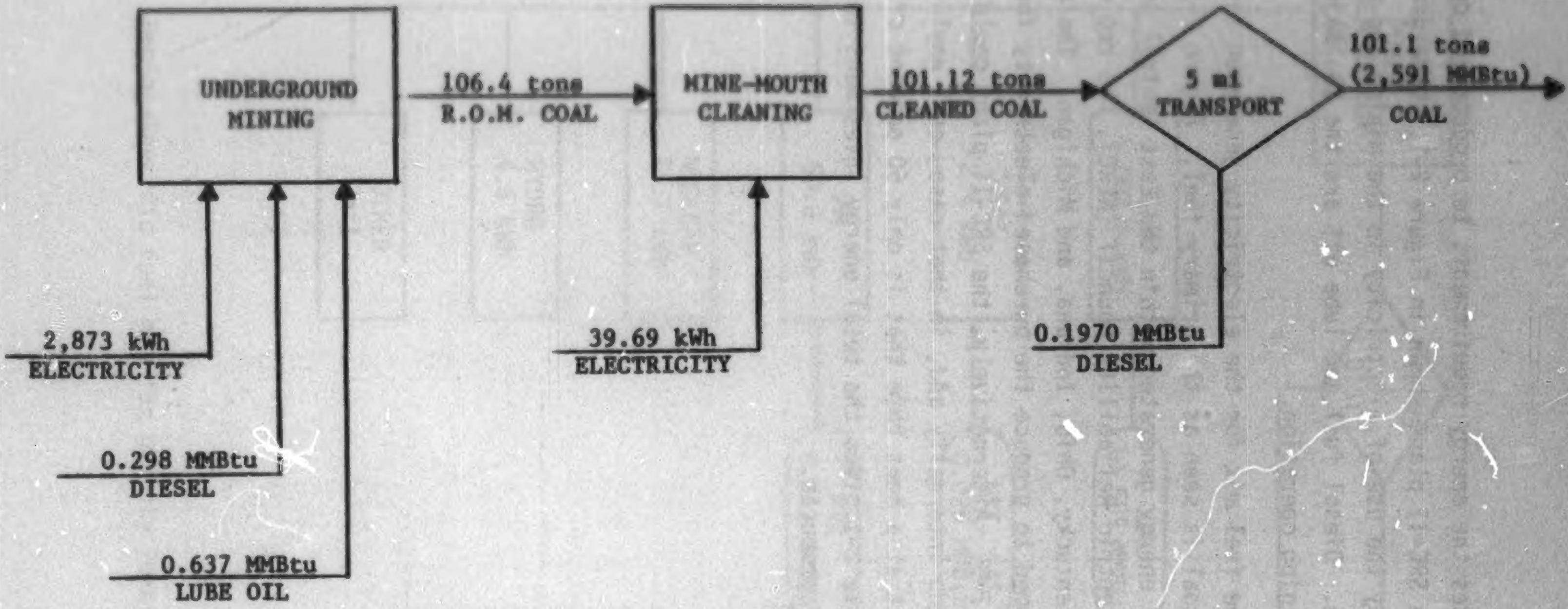

101.1 tons
(2,591 MMBtu)
COAL
FEEDSTOCK - 2,187 MMBtu
FUEL - 404 MMBtu
2,044 GAL.
RAW Water
CATALYSTS
& CHEMICALS
755.5 kWh
PURCHASED ELECTRICITY
SRC-II LIQUEFACTION
1,000 MMBtu FUEL OIL
PRODUCT
145.0 MMBtu PIPELINE GAS
287.8 MMBtu NAPHTHA
383.2 MMBtu C2's & C3's
38.1 MMBtu C4's
COPRODUCTS
7,129 lbs. SULFUR
1,108 lbs. AMMONIA
225 lbs. TAR ACIDS
BY-PRODUCTS
NOTE: MMBtu = 10^6 Btu

Figure 2-1. Energy Flows in the Production of 1,000 MMBtu of Fuel Oil by SRC-II

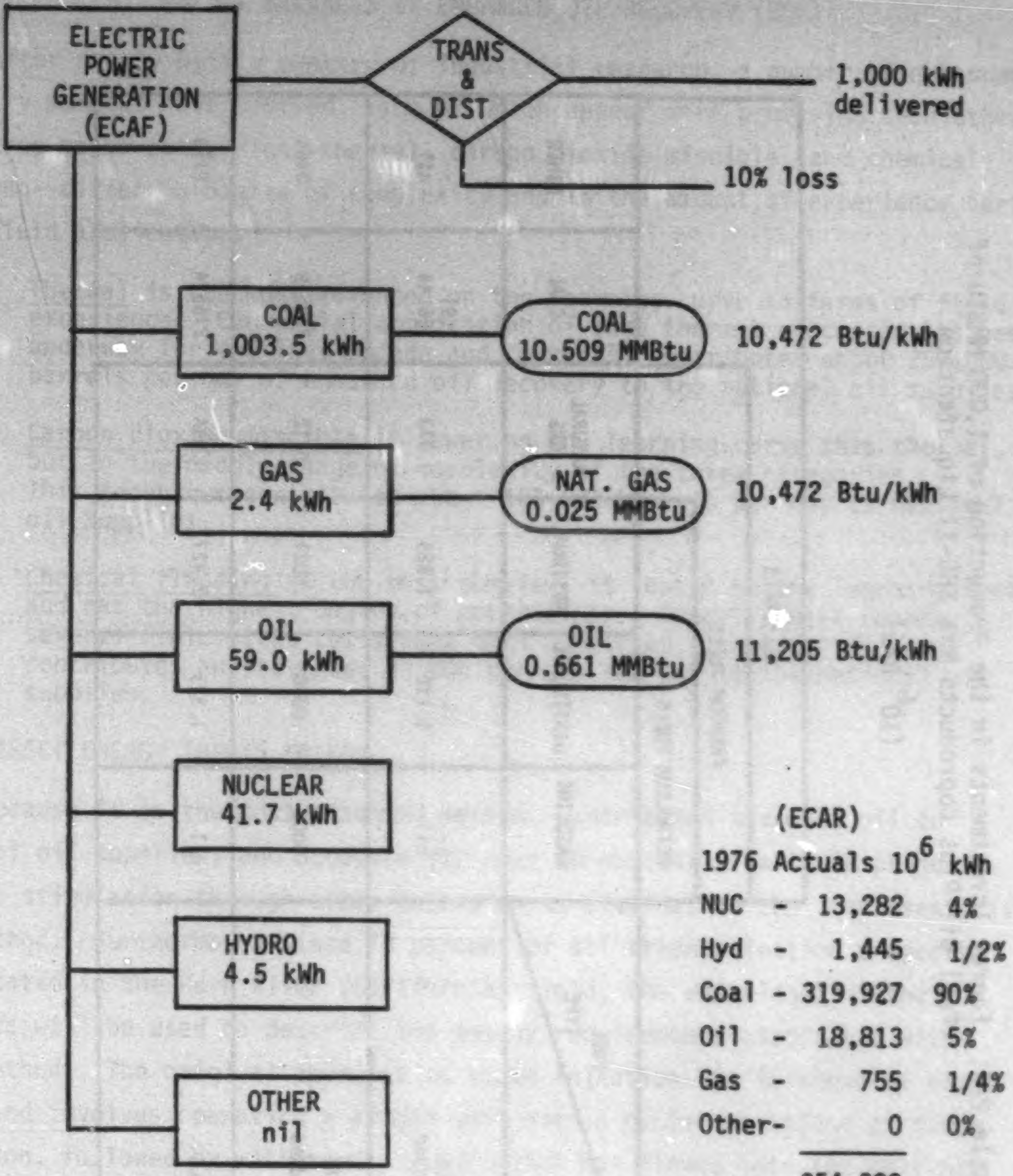

UNDERGROUND MINING
106.4 tons
R.O.M. COAL
MINE-MOUTH CLEANING
101.12 tons
CLEANED COAL
5 mi TRANSPORT
101.1 tons
(2,591 MMBtu)
COAL
2,873 kWh
ELECTRICITY
0.298 MMBtu
DIESEL
0.637 MMBtu
LUBE OIL
39.69 kWh
ELECTRICITY
0.1970 MMBtu
DIESEL

NOTE: MMBtu = 10^6 Btu

Figure 2-2. Energy Inputs to Coal Mining to Provide Coal Feedstock for SRC-II

Figure 2-2 illustrates the energy requirements to produce and deliver 101.1 TPD of coal for the SRC-II plant shown in Figure 2-1. Underground mining is characterized by the use of electricity in the mining and movement of coal to the mine-mouth. Diesel fuel and lube oil are the two major, non-electric inputs to the mining operation.

In characterizing the fuel mix for the electricity generated for consumption in the Morgantown area, coal is seen as the primary fuel. Figure 2-3 illustrates the breakdown of electric energy generated within the East Central Area Region (ECAR) of the National Electric Reliability Council (NERC), the region which includes West Virginia, Kentucky, Ohio, Indiana, and Michigan. The allocation of energy resources consumed to produce the purchased electricity for the SRC-II plant is based on Figure 2-3. Alternatively, the SRC-II plant could cogenerate its electrical energy needs internally and, in that case, coal would supply all the primary energy, albeit at a heat rate that is only 60 percent of a typical utility power plant. Table 2-1 gives the total energy investment to produce 1,000 MMBtu/day of SRC-II products.


ELECTRIC POWER GENERATION (ECAF)
TRANS & DIST
1,000 kWh delivered
10% loss
COAL 1,003.5 kWh
COAL 10.509 MMBtu
10,472 Btu/kWh
GAS 2.4 kWh
NAT. GAS 0.025 MMBtu
10,472 Btu/kWh
OIL 59.0 kWh
OIL 0.661 MMBtu
11,205 Btu/kWh
NUCLEAR 41.7 kWh
HYDRO 4.5 kWh
OTHER nil

(ECAR)

1976 Actuals 10^6 kWh		
NUC -	13,282	4%
Hyd -	1,445	1/2%
Coal -	319,927	90%
Oil -	18,813	5%
Gas -	755	1/4%
Other-	0	0%
	354,222	

Figure 2-3. Region-Specific Fuel Mix for Utility Power Generation (ECAR Region)

Table 2-1. Energy Investments in the Production of 1,000 MMBtu of Fuel Oil Plus Coproducts via SRC-II Liquefaction

(10^6 Btu)

	ALL FUELS					
	PREMIUM FUELS					
	PETROLEUM FUELS					
SRC-II INPUT / FUEL TYPE	GASOLINE	DISTILLATE	RESIDUAL	NATURAL GAS	COAL	OTHER
COAL • Direct • Embedded	-- nil	-- 1.132	-- 1.925	-- 0.073	2591. 166.44	-- nil
ELECTRICITY • Embedded	.0000	.0008	.5021	.0212	7.9519	.0165
TOTALS	nil	1.333	2.427	0.094	2765.4	.0165

TOTAL ENERGY INVESTED = 2,769.1 MMBtu

3. ENERGY BALANCES OF ENHANCED OIL RECOVERY (EOR)

After nearly half a century of industrial research, a number of enhanced recovery methods have evolved, some of which appear more promising than others. The three major categories--thermal, carbon dioxide miscible, and chemical flooding--differ in degree of complexity and in the amount of experience derived from field applications:

- Thermal is the most advanced on the learning curve in terms of field experience. Commercial application of some thermal processes has been underway for the last decade and currently contributes about 250,000 barrels per day of enhanced oil recovery to the national oil supplies.
- Carbon dioxide miscible is lower on the learning curve than thermal, but in the middle range of complexity of the three categories. This technique contributes about 100,000 barrels per day to national oil supplies.
- Chemical flooding is the most complex, is lowest on the learning curve, and has the highest degree of uncertainty. Over the past decade, several field pilot tests have been conducted. Chemical flooding contributes an estimated 23,000 barrels per day to the national oil supplies.

3.1 DIRECT ENERGY INPUTS TO EOR

Because it is the most advanced method, contributes the most oil to national oil supplies, and accounts for over 50 percent of all EOR projects, thermal stimulation through steam injection is examined as the "representative" EOR method. Furthermore, since 73 percent of all steam injection projects are located in the Kern River (California) field, the experience of these projects will be used to describe the energy requirements associated with this method. The original approach to steam injection EOR is known as steam soak, and involves operating a single well over a cycle consisting of steam injection, followed by withdrawal of oil which has flowed into the well by reason of its reduced viscosity. This approach is being replaced by a steam drive approach involving injection of steam into alternate wells, to heat the oil and drive it to adjacent offsetting wells.

The steam drive works somewhat differently than might be expected from its name. Instead of pushing, or driving, the oil ahead of it, steam flows over the oil, transferring heat by conduction to the column of oil beneath it. Oil at the interface between the steam and the oil column, its viscosity reduced, is then dragged along by the steam to the producing well. Even in some of the most favorable reservoirs, it is necessary to use energy equivalent to burning at least 25 percent of the crude oil produced, in order to generate the required amount of steam; and in California the current average is about 35 percent.* That value will be used to characterize thermal EOR for this study.

Figure 3-1 presents the energy inputs required to produce 1,000 MMBtu of crude via an "average" conventional oil-recovery process. The data source for this characterization is the 1976 report, "Energy Use in Petroleum Refineries," Oak Ridge National Laboratory (V. O. Haynes) ORNL/TM-5433.

Figure 3-2 presents the energy inputs required to produce 1,000 MMBtu of "useful" crude oil via the assumed steam-injection thermal EOR process. This characterization assumes that 35 percent of the crude extracted from the field is burned on-site to generate steam. A total of 1,538 MMBtu of crude must be recovered to net the 1,000 MMBtu of useful crude oil output. The direct energy investments for recovery of "stimulated" crude are based on the conventional process of Figure 3-1 scaled to 1,538 MMBtu of crude oil recovered.

Figure 3-3 presents the energy inputs required to produce 1,000 MMBtu of "useful crude oil via steam-injected thermal EOR if coal is used instead of crude oil to fire the on-site boilers. Figure 3-3 assumes that an on-site boiler may be fired with coal at about the same boiler efficiency as when crude oil is burned. Because the process does not incur the internal loss of 35 percent of the gross crude oil recovered, the direct energy investments per 1,000 MMBtu of "useful" crude oil are identical to those for conventional recovery (Figure 3-1). The rationale for examining this case is found in the fact that substituting coal-firing for crude oil firing has the same impact as coal liquefaction, but at a potentially more favorable energy efficiency.

3.2 INDIRECT ENERGY REQUIREMENTS FOR THERMAL EOR

The indirect energy investments for thermal EOR include the energy which is involved in generating the electric power input plus the energies required to produce the other direct energy inputs. The quantity of direct energy inputs is small relative to the energy contained in the crude oil produced, making

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*Doscher, T. M., "Enhanced Recovery of Crude Oil," American Scientist, Vol. 69, No. 2, pp. 193-199 (March 1981).

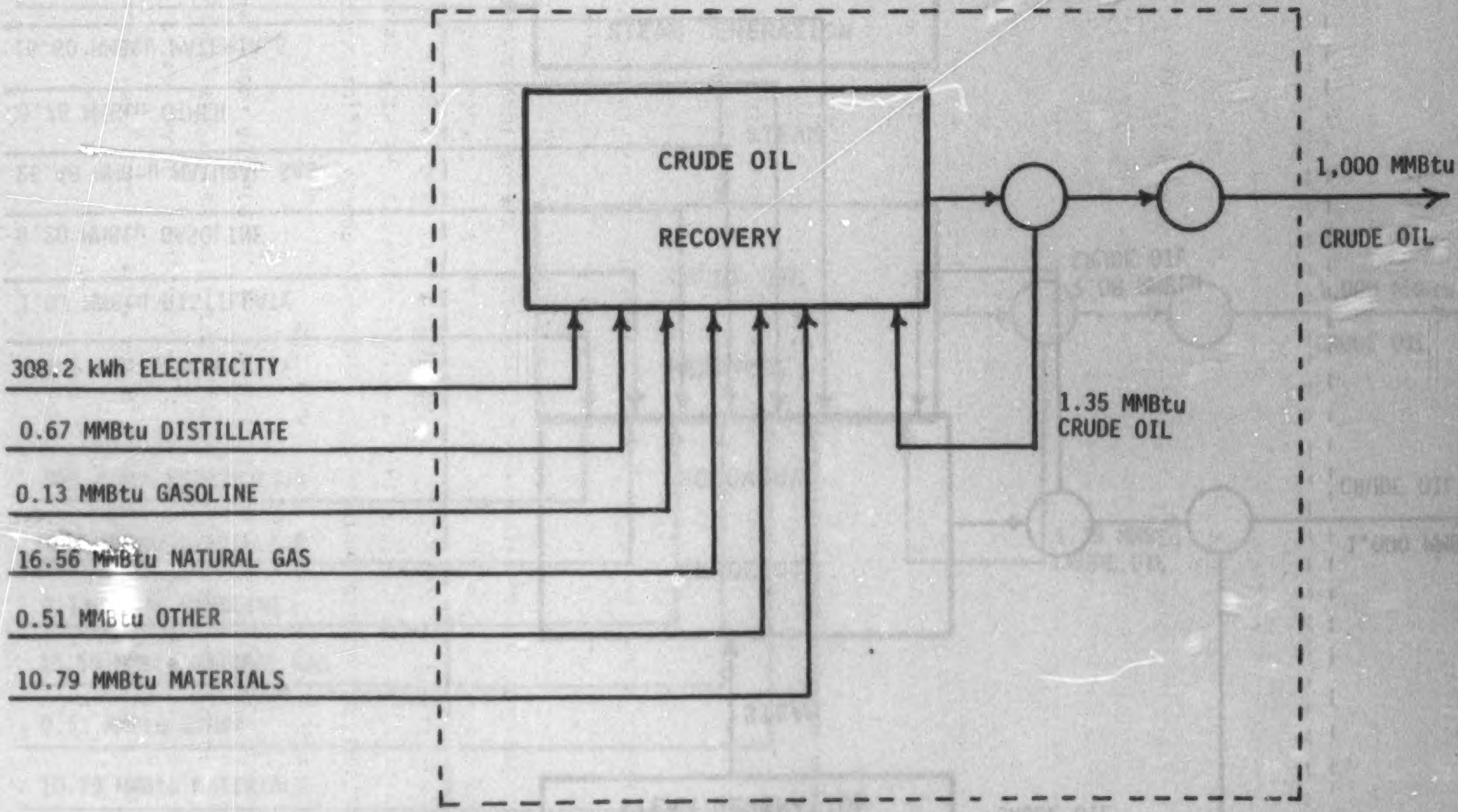
CRUDE OIL
RECOVERY
1,000 MMBtu
CRUDE OIL
1.35 MMBtu
CRUDE OIL
308.2 kWh ELECTRICITY
0.67 MMBtu DISTILLATE
0.13 MMBtu GASOLINE
16.56 MMBtu NATURAL GAS
0.51 MMBtu OTHER
10.79 MMBtu MATERIALS

Figure 3-1. Energy Investments in Conventional Petroleum Recovery

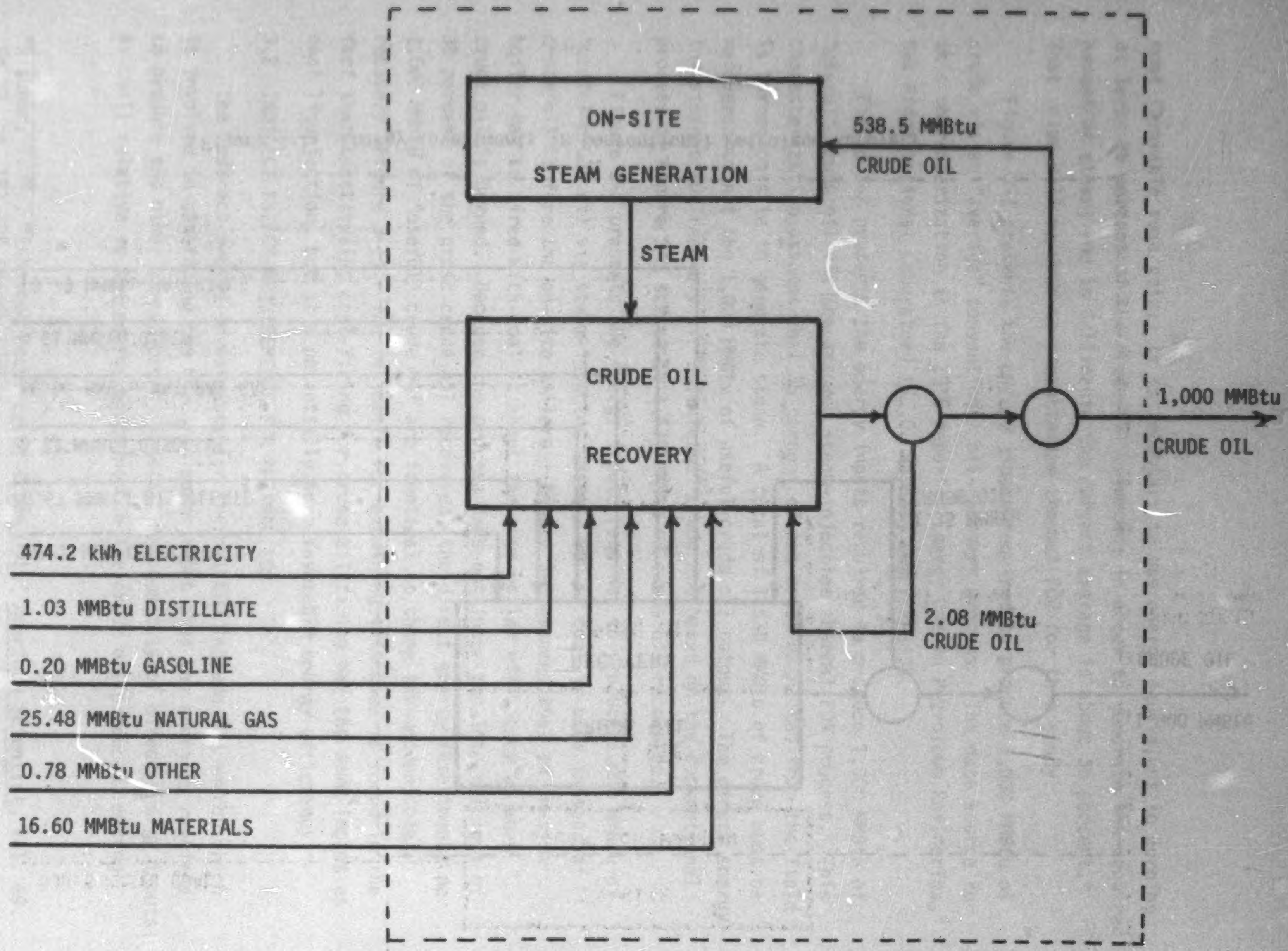
ON-SITE
STEAM GENERATION
538.5 MMBtu
CRUDE OIL
STEAM
CRUDE OIL
RECOVERY
1,000 MMBtu
CRUDE OIL
2.08 MMBtu
CRUDE OIL
474.2 kWh ELECTRICITY
1.03 MMBtu DISTILLATE
0.20 MMBtu GASOLINE
25.48 MMBtu NATURAL GAS
0.78 MMBtu OTHER
16.60 MMBtu MATERIALS

Figure 3-2. Energy Investments in Steam-Injection Thermal EOR (Crude-Fired)

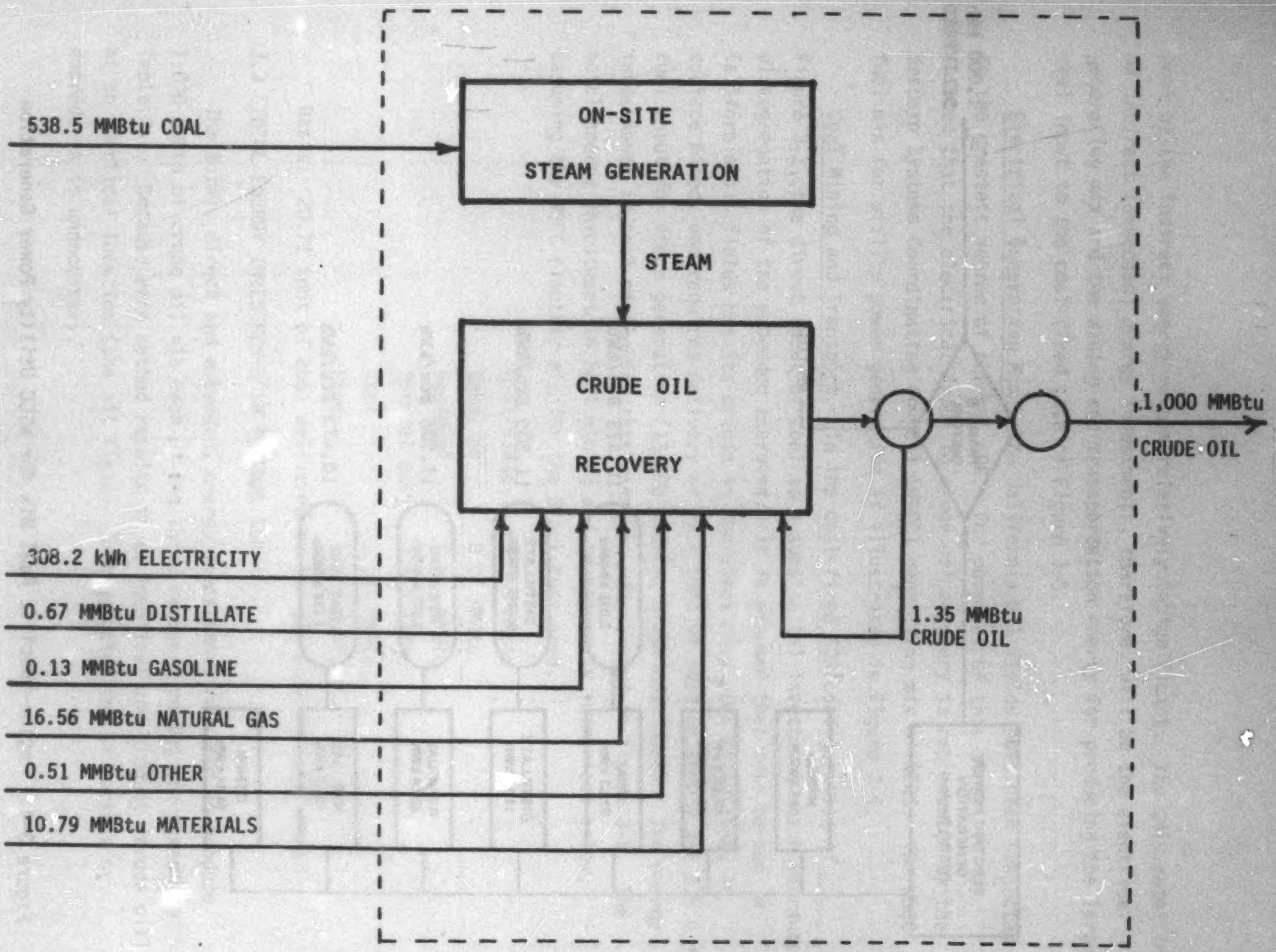
538.5 MMBtu COAL
ON-SITE
STEAM GENERATION
STEAM
CRUDE OIL
RECOVERY
308.2 kWh ELECTRICITY
0.67 MMBtu DISTILLATE
0.13 MMBtu GASOLINE
16.56 MMBtu NATURAL GAS
0.51 MMBtu OTHER
10.79 MMBtu MATERIALS
1.35 MMBtu
CRUDE OIL
1,000 MMBtu
CRUDE OIL

Figure 3-3. Energy Investments in Steam-Injection Thermal EOR (Coal-Fired)

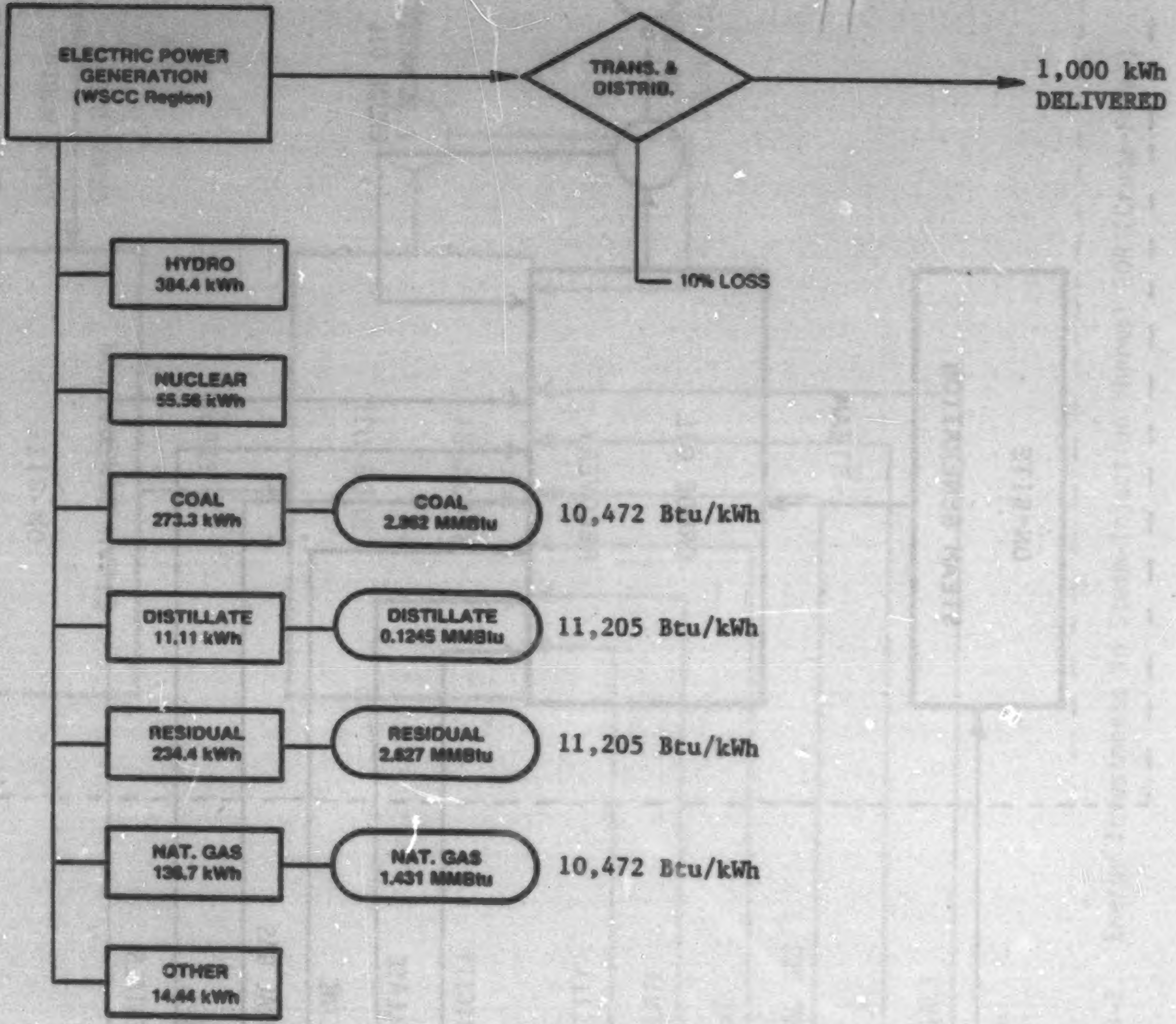
ELECTRIC POWER GENERATION (WSCC Region)
TRANS. & DISTRIB.
1,000 kWh DELIVERED
10% LOSS
HYDRO 384.4 kWh
NUCLEAR 55.56 kWh
COAL 273.3 kWh
COAL 2.862 MMBtu
10,472 Btu/kWh
DISTILLATE 11.11 kWh
DISTILLATE 0.1245 MMBtu
11,205 Btu/kWh
RESIDUAL 234.4 kWh
RESIDUAL 2.627 MMBtu
11,205 Btu/kWh
NAT. GAS 136.7 kWh
NAT. GAS 1.431 MMBtu
10,472 Btu/kWh
OTHER 14.44 kWh

Figure 3-4. Region-Specific Fuel Mix for WSCC Utility Power Generation

most of the indirect energy values relatively insignificant. The only detailing of indirect (embedded) energy investments, therefore, will be the electrical generating mix and the mining and transportation energy for producing the large coal input to the coal-fired case of Figure 3-3.

Electrical Generating Mix. The California oil fields have been subjected to the greatest degree of thermal EOR. For purposes of this study, it is assumed that the electrical input to crude oil recovery is represented by the Western Systems Coordinating Council (WSCC) generating mix of NERC. The WSCC fuel mix for utility power generation is illustrated in Figure 3-4.

Coal Mining and Transport. In the coal-fired EOR configuration of Figure 3-3, the direct input of coal is a substantial investment which warrants disaggregation of the embedded energies. It is assumed that coal burned in California oil fields has its origin in the Black Mesa area of Arizona, is surface mined, and requires delivery of 20.7 tons of coal to supply the 538.5 MMBtu fuel input for steam generation (13,000 Btu/lb, bituminous coal). The energy investments in coal mining for this case are illustrated in Figure 3-5. The total energy investment in coal mining and transport is summarized below, assuming the WSCC electric mix for the Black Mesa area.

Distillate	-	5.389 MMBtu
Gasoline	-	0.07 MMBtu
Residual	-	1.036 MMBtu
Natural Gas	-	0.564 MMBtu
Coal	-	1.128 MMBtu
Other	-	1.559 MMBtu

Basis: 20.71 tons of coal delivered to the EOR site in California

3.3 TOTAL ENERGY INVESTMENTS IN THERMAL EOR

The total, direct and embedded, energy investments required to produce 1,000 MMBtu of crude oil via each of the three recovery routes are given in Table 3-1. Because each method results in an identical end product (crude oil) at an identical location (the oil field), further detailing of markets or coproducts is unnecessary.

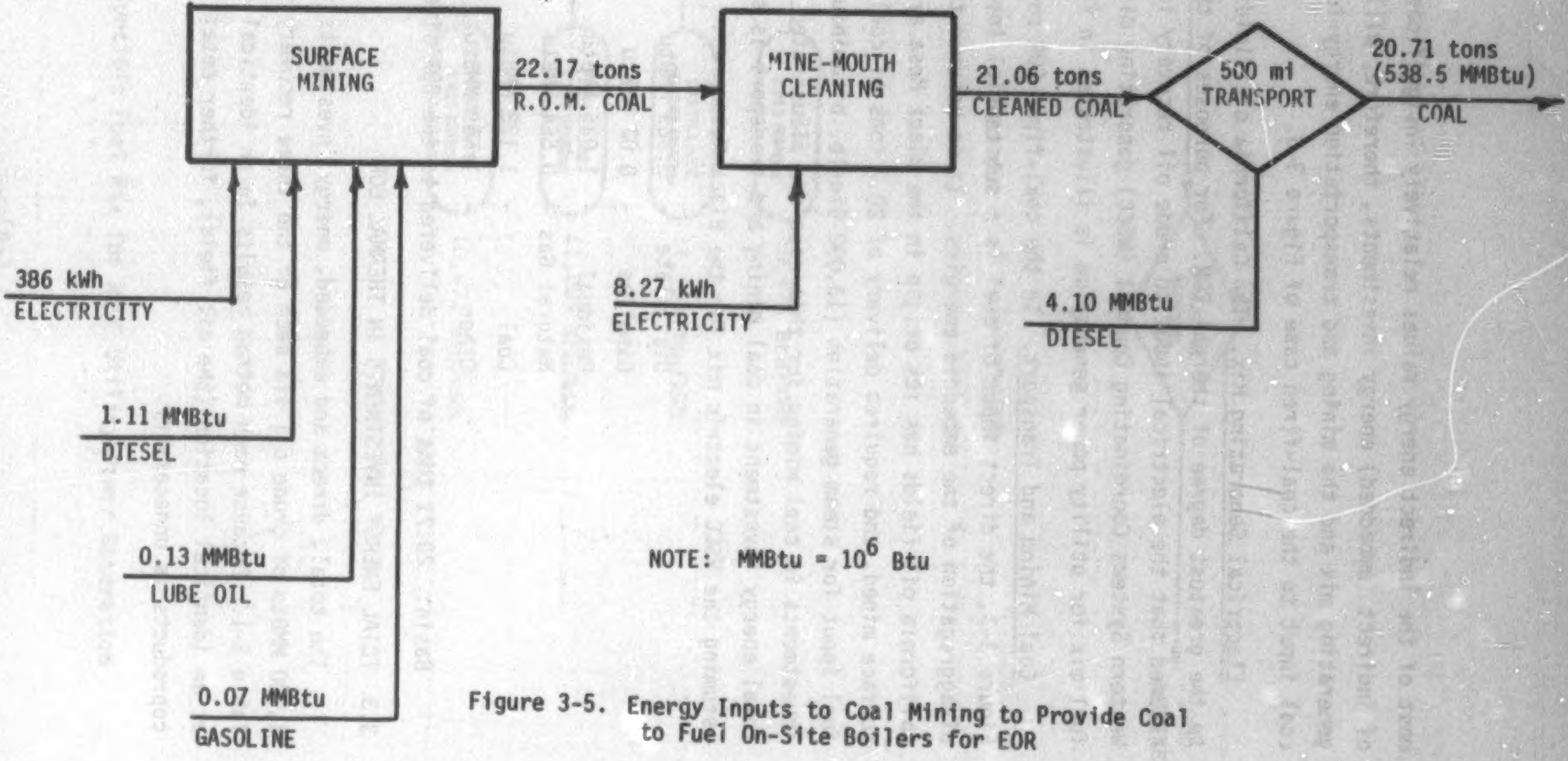
SURFACE MINING
22.17 tons
R.O.M. COAL
MINE-MOUTH CLEANING
21.06 tons
CLEANED COAL
500 mi TRANSPORT
20.71 tons
(538.5 MMBtu)
COAL
386 kWh
ELECTRICITY
1.11 MMBtu
DIESEL
0.13 MMBtu
LUBE OIL
0.07 MMBtu
GASOLINE
8.27 kWh
ELECTRICITY
4.10 MMBtu
DIESEL
NOTE: MMBtu = 10⁶ Btu

Figure 3-5. Energy Inputs to Coal Mining to Provide Coal to Fuel On-Site Boilers for EOR

Table 3-1. Total Energy Investments in Three Crude Oil Recovery Methods

(10^6 Btu)

FUEL TYPE	ALL FUELS					
	PREMIUM FUELS					
	PETROLEUM FUELS					
	GASOLINE	DISTILLATE	RESIDUAL	NATURAL GAS	COAL	OTHER
CONVENTIONAL OIL RECOVERY						
• DIRECT	0.13	0.67	nil	16.56	nil	11.30
• EMBEDDED	nil	0.039	0.810	0.441	0.882	1.55
• TOTAL	0.13	0.708	0.810	17.00	0.882	12.85
EOR (CRUDE-FIRED)						
• DIRECT	0.20	1.03	nil	25.48	nil	17.38
• EMBEDDED	nil	0.058	1.246	0.679	1.357	2.39
• TOTAL	0.20	1.088	1.246	26.16	1.357	19.77
EOR (COAL-FIRED)						
• DIRECT	0.13	0.67	nil	16.56	538.5	11.30
• EMBEDDED	0.07	5.427	1.846	1.005	2.01	3.109
• TOTAL	0.20	6.097	1.846	17.57	540.5	14.41

3.4 ENERGY DISPLACEMENTS FOR THERMAL EOR

Formulation of energy balances for thermal EOR versus conventional oil recovery and increased use of imported oil follows the same logic used by TRW in its March 1981 study of NOSR 1.

The EOR crude is assumed to displace imported crude oil of a comparable quality on a barrel-per-barrel basis. For refining in the California area, the energy savings that can be ascribed to the 1,000 MMBtu of EOR crude, corresponding to the energy in an equivalent amount of imported crude oil (at 5.8 MMBtu/barrel) landed in California.

3.5 ENERGY BALANCES FOR THERMAL EOR

The energy balances for the three oil recovery routes are summarized below in Table 3-2. For the purpose of establishing the balances, the energy investments are taken to be the totals presented in Table 3-1, and the savings are taken to be the 1,000 MMBtu of imported crude which is displaced by increased domestic production.

Table 3-2. Energy Balances for Thermal EOR

	Petroleum Fuels	All Fuels
(1) Conventional Recovery	(MMBtus)	
• Investments	1.65	32.38
• Savings	1,000	1,000
• Gain Ratio*	605:1	29.9:1
(2) Thermal EOR (crude-fired)		
• Investments	2.53	49.82
• Savings	1,000	1,000
• Gain Ratio*	394:1	19.1:1
(3) Thermal EOR (coal-fired)		
• Investments	8.14	580.6
• Savings	1,000	1,000
• Gain Ratio*	122:1	0.72:1

* Gain Ratio = (Savings-Investment)/Investment

4. ENERGY BALANCES: OUTER CONTINENTAL SHELF DRILLING (OCS)

The third technology considered as an alternative to NOSR is drilling on the Outer Continental Shelf (OCS). The drilling and production technology used in the Gulf of Mexico was chosen as representative of OCS in this study.

Conventional fixed platforms are used for most Gulf of Mexico oil production. These are typically steel jacketed structures which rest on the sea floor. Wells are drilled from these platforms, and oil, water and natural gas from the wells are separated on the platforms. The water is either reinjected or treated and disposed of. The oil is metered and piped or shipped to shore. Natural gas is dehydrated, pressurized, metered, and piped to shore.

Industry sources indicate that an average of 18,000 BPD are produced from a typical 35 million barrel reserve. A single 24-slot platform would be used to develop the field.

4.1 DIRECT ENERGY USE IN OCS PRODUCTION

OCS is a capital-intensive oil recovery process. The energy investment for OCS is small in comparison to the capital and labor requirements and in comparison to OCS energy production. Nonetheless, there is an energy component in OCS, primarily from operation of the rig itself, and to power supply craft which support both the drilling rig and the production and pipeline activities.

A Booz-Allen study* completed in 1977 offered the following energy consumption estimates for an OCS rig:

Subsector	Estimated Energy Consumption (BOE/day)
Drilling Rigs	100
Supply craft supporting drilling rigs	99.3
Supply craft supporting production and pipelaying activities	37.4
	237 BOE/day

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*Energy Use in the Marine Transportation Industry, Booz-Allen & Hamilton, Inc., for USDOE, SAN-1175-T2 (Vol. 2), September 1977.

Because of the nature of these energy investments, it is reasonable to assume that they are entirely petroleum-derived, namely, gasoline and diesel fuels.

4.2 ENERGY DISPLACEMENTS FOR OCS RECOVERY

The OCS crude is assumed to displace imported crude oil of a comparable quality on a barrel-per-barrel basis. In addition to the 18,000 BPD petroleum production, it is assumed that the wells will produce 16 million CFD of gas which is recovered and transported to the U.S. markets. The displacement values of the petroleum and natural gas from a single OCS platform are given in Table 4-1.

Table 4-1. Energy Displacements for a Typical OCS Drilling Platform (10^6 Btu)

Product	Petroleum Fuels	All Fuels
Crude Oil		
• Direct	104,400	104,400
Natural gas		
• Direct	--	16,304
• Indirect	16.5	108.5
• Total	16.5	16,412

These displacement values for natural gas are based on the actual energy resources produced plus the embedded energy required to produce them via conventional means. The embedded investments in crude oil are not included because it is assumed that it will displace imported petroleum for which there has been no U.S. investment of energy resources.

4.3 ENERGY GAIN RATIOS FOR OCS PRODUCTION

	Petroleum Fuels	All Fuels
Investment	1,375 MMBtu	1,375 MMBtu
Savings*	104,417 MMBtu	120,812 MMBtu
Energy gain ratio**	75:1	87:1

*Includes the value of imported crude displaced plus the direct and embedded values for natural gas.

**Ratio = (Savings-Investment)/Investment

5. SUMMARY

5.1 OIL SHALE ON NOSR 1

Energy invested = 32,955 MMBtu
Energy produced = 339,462 MMBtu

$$\text{Net energy efficiency} = \frac{339{,}462 - 32{,}955}{339{,}462} \times 100$$

$$= 90.3 \text{ percent}$$

1 BOE invested yields: 8.8 bbls liquid
10.3 BOE energy products

5.2 COAL LIQUEFACTION, SRC II

Energy invested = 2,769.1 MMBtu
Energy produced = 1,854.1 MMBtu

$$\text{Net energy efficiency} = \frac{1{,}854.1 - 2{,}769.1}{1{,}854.1} \times 100$$

$$= -49.4 \text{ percent}$$

1 BOE invested yields: 0.4 bbl liquids
0.7 BOE energy products

For the case of captive coal supplies, though unlikely, the figures are as follows:

Energy invested = 532 MMBtu
Energy produced = 1,854.1 MMBtu

$$\text{Net energy efficiency} = \frac{1{,}854.1 - 582}{1{,}854.1} \times 100$$

$$= 68.6 \text{ percent}$$

1 BOE invested yields: 2.0 bbls liquids
3.2 BOE energy products

5.3 ENHANCED OIL RECOVERY (EOR), STEAM INJECTION

Energy invested = 49.8 MMBtu
Energy produced = 1,000 MMBtu

$$\text{Net energy efficiency} = \frac{1{,}000 - 49.8}{1{,}000} \times 100$$

$$= 95.0 \text{ percent}$$

1 BOE invested yields: 20.1 bbls liquids
20.1 BOE energy products

5.4 OUTER CONTINENTAL SHELF (OCS)

Energy invested = 1,375 MMBtu

Energy produced = 120,812 MMBtu

$$\text{Net energy efficiency} = \frac{120{,}812 - 1{,}375}{120{,}812} \times 100$$

$$= 98.9 \text{ percent}$$

1 BOE invested yields: 75.9 bbls liquid
87.9 BOE energy products

5.5 BIOMASS/ALCOHOL*

Energy invested = 91.5 MMBtu

Energy produced = 84.2 MMBtu

$$\text{Net energy efficiency} = \frac{84.2 - 91.5}{84.2} \times 100$$

$$= -\,8.7 \text{ percent}$$

1 BOE invested yields: 0.9 bbls liquids
0.9 BOE energy products

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* Reference: "Energy Balances in the Production and End Use of Alcohol Derived from Biomass and Coal," U.S. DOE and National Alcohol Fuels Ommission, November, 1979.

[illegible]

[illegible]

Energy invested = [illegible] MMBtu

Energy produced = [illegible]

Net energy efficiency = [illegible]

= [illegible] percent

1 BOE invested yields [illegible] bbls liquids

[illegible] BOE energy produced

[illegible]

Energy invested = [illegible]

Energy produced = [illegible]

Net energy efficiency = [illegible]

= [illegible] percent

1 BOE invested yields [illegible]

[illegible] BOE energy produced

For the case of [illegible], though unlikely, the figures are as follows:

Energy invested = [illegible] MMBtu

Energy produced = [illegible] MMBtu

Net energy efficiency = [illegible]

= [illegible] percent

1 BOE invested yields [illegible] bbls liquids

[illegible] BOE energy produced

[illegible]

Energy invested = [illegible]

Energy produced = [illegible]

Net energy efficiency = [illegible]

1 BOE invested yields [illegible] bbls liquids

[illegible] BOE energy produced

APPENDIX D. COMMUNITY ASSISTANCE PROGRAMS

D.1 IMPACT ASSISTANCE

STATE AND FEDERAL POLICIES FOR IMPACT ASSISTANCE

Although both the State of Colorado and the federal government have taken steps to address the socioeconomic impacts of major energy development, their approaches and attitudes vary significantly. Since the early seventies, Colorado has been developing a progressive, comprehensive, and coherent program to assist communities which will be affected by oil shale development. The community assistance effort is coordinated by the Socio-Economic Impact Office and funded primarily by revenues obtained from the Oil Shale and Severance Tax Trust Funds. On the other hand, except for a few specific and modest programs, the federal government has not assumed responsibility for energy impact problems, except through other categorical programs not specifically designed to address the particular problems of energy-impacted communities.

Federal Policies

There are currently only three programs specifically geared to addressing the problems of energy impacted communities -- the Coastal Energy Impact Program (CEIP), the Farmers Home (Fm HA) 601 Impact Assistance Program, and the 1920 Mineral Leasing Act and subsequent amendments which provide the states with up to 50% of the monies collected for federal leasing activities, including federal oil shale lands. Both the CEIP and the Fm HA 601 program are not applicable for oil shale development. To the extent that the federal government is active in addressing socioeconomic impact problems, it is generally to mitigate the impacts of direct federal actions, policy, or initiatives such as offshore oil development, mineral leasing, and location or closing of major federal installations. The policy implicit in these programs is that the local and state governments are primarily responsible for managing and regulating the effects of federal decisions and that federal money will be provided only where shortfalls can be documented and all routine sources exhausted. The CEIP is instructive with

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NOTE: This study was prepared in 1980. Some of the programs identified in this section may have undergone revisions or restructuring since this section was prepared. The information in this section will be reviewed and updated should it be proposed at some future date to develop NOSR 1.

regard to federal policy. Under the CEIP, there is a three-step process which must be satisfied to obtain funding. First, the affected community must demonstrate that it has exhausted all existing categorical programs and other possible sources of funding before assistance will be provided. Second, loans and loan quarantees will be made available for specific problems. Finally, after it has been demonstrated that these programs are inappropriate or inadequate, grants will be provided.

Congressional attitude towards impact assistance has been characterized by a lack of priority, in part reflecting the lack of political visibility of the essentially rural problem. Problems of the inner city and economically depressed areas have naturally commanded greater priority than the problems of rapid population and economic growth. Since it is expected that boomtowns will eventually realize significant revenues from large-scale development, the financial stress experienced by boomtowns is regarded as a temporary phenomenon, although experience indicates that initial imbalances may never be overcome by latter revenues produced by a project.

Federal policy towards impact assistance, therefore, is neither coherent, comprehensive, or coordinated. Rather it is implicit in the myriad of fragmented categorical programs which can potentially be brought to bear in a reactive fashion to various problems -- sewers, water, housing, crime, etc. As a result, federal policy is non-explicit, fragmented, varies widely from one agency to another, and directed much more towards urbanized than urbanizing areas. Since the programs are not designed or coordinated specifically to address impact problems, they are often inappropriate, involve inflexible and complicated requirements, involve long lead times, and do not provide the magnitude of assistance the problems demand.

State Policy

Beginning in the mid-seventies, the Colorado Legislature passed several pieces of legislation which in total establish an energy impact assistance program and policy. In 1974, the Oil Shale Lease Fund was created by placing the oil shale payments received by the state from the 1920 Mineral Leasing Act in a special fund for planning and the provision of public services. In 1975, the legislature provided for the use of the interest from the Oil Shale Trust for impact assistance as well. The Socio-Economic Impact Office was established after the creation of the Oil Shale Trust and its duties enhanced in 1977 with the passage of the state severance tax which created an Impact Assistance Fund. With these and other funds, the Impact Office currently administers approximately $8 million of grants to local and county governments to meet various impact problems.

The State of Colorado believes that local communities should not have to shoulder extensive debts in order to provide basic services to accommodate new energy development. As a result, most of the expenditures have been for the immediate problems of roads, schools, water and sewer, and human services such as mental health and alcoholism treatment. In addition, the Impact Office has helped provide technical assistance to beef up local capability to manage new development with the aim of encouraging future financial self-sufficiency. The aim of the program is to develop local awareness of energy impact problems and develop local financial structures which address impact requirements. The Impact Program is designed to support local governments who have the primary responsibility to plan for and mitigate adverse impacts. The Impact Program sees its responsibilities as providing the technical resources to accomplish long-range local self-sufficiency, coordinate the use of a variety of funds to address impact problems, and use its own resources as the "last dollar in" to resolve locally identified problems. The Impact Office is also designed to coordinate state and federal programs which might be of assistance to communities as well as foster communication among various levels of government and industry.

In order to keep impacts at a mangeable level, the state has encouraged a phased development approach on the part of the oil shale developers. While the definition of "phased" development is somewhat vague, it has been utilized most commonly to refer to the construction of demonstration modules prior to the actual construction of full scale commercial plants. The reasons that it is only after experience has been gained with the demonstration modules that effective and appropriate programs can be implemented to handle commercial-scale operations. To meet the needs of impacted areas, the state has encouraged the formation of local and county-wide impact teams to perform the following tasks:

a. Research and application of impact data to the unique local situation in an effort to identify problems and to tailor the solutions to the local area.

b. The setting of local priorities and the development of local criteria which address the phasing of local development projects in a logical framework.

c. The screening and endorsement of applications for financial or technical assistance to state, federal and industry sources.

The state also has an Energy Impact Assistance Advisory Committee to formulate policy and help administer the grant programs of the Local Government Severance Tax Fund. Attached are the impact policies utilized by the Committee in evaluating proposals. Since the inception of the program, 159 applications have been received totalling $22.1 million, and 96 awards have been made totalling approximately $6.1 million.

1. $200,000 Per Project Limit on Impact Assistance Grants

The Committee has used an informal limit of $200,000 in impact assistance funds for a single project. This limit has developed primarily from a concern that the small amount of funds available annually for distribution would not go very far if many extremely large grants were approved. While any project will be seriously considered if sufficient justification is provided, the chances for project approval generally diminish as the request amounts increase.

2. State Committee Consistency with Local Priorities

The Committee agreed in its early stages to follow local area priorities as much as possible. Problems subsequently developed because local committees often provided very little information to justify their priorities, or failed to set priorities at all. Now that the local impact teams and the State are working more closely together, local priorities will be closely adhered to except:

A. When the higher priority projects request more money than the Committee is able to commit at this time.

B. When a high priority project conflicts with an existing State plan or policy, as identified in the A-95 Reviews.

C. When a higher priority project requests matching funds contingent upon receipt of other funds not yet approved. In this instance the project may be deferred until the matching funds are received.

3. Operating Deficits

The Committee is generally opposed to funding operating deficits, however, each such application will be considered on an individual basis.

4. Leveraging Other Funds

The Committee encourages projects that leverage other sources of funds, such as federal grants and loans.

5. Industry Match

The Committee encourages projects with a high level of industry match. However, industry participation will be considered within the context of all that industry is doing in an area, rather than a percentage participation in each project. It will be the responsibility of the applicant to provide information on industry participation.

6. Local Government Responsibility

The Committee urges local governments to take primary responsibility in resolving problems related to impact. In specific projects, this may involve adjusting user rates and fees, creation of improvement districts in some instances, and generally sharing in the cost of development.

7. Last Dollar In

The Committee encourages applicants to exhaust all other potential sources of funding before requesting impact assistance funds.

8. Local Impact Teams

The Committee strongly encourages the formation of local impact teams, and discourages applications that are submitted without local impact team review. The Committee encourages local impact teams to thoroughly review applications, to suggest modification or withdrawal of applications when appropriate and to fully document local priorities.

9. Special Interest Applications

The Committee discourages applications designed to primarily serve private developers, industry and special interest groups which are not meeting a clearly defined local need.

10. Formula Distribution of Funds

Applications are considered on an individual basis within the context of local priorities, and no formula distribution of funds by geographic area will take place.

11. Priority Types of Applications

Applications are reviewed on individual merit without receiving any additional consideration because it fits a special category, such as water, sewer, or public safety.

12. Operating Funds

The Committee has placed a one-year limit on operating fund projects, requiring the local entity to commit to second-year funding. The Committee will consider special circumstances affecting such requests.

13. Full Disclosure

Applicants must supply full financial information and other pertinent information affecting their request. In the past, some applications have reflected that a community was in serious financial difficulty when in fact it had large unallocated surpluses.

14. Incorporation of State Policies

Whenever possible, the Committee will consider existing State program policies in their decisions.

15. Loans

Loans will be encouraged in those instances where the applicant has the potential to generate repayment revenues.

16. Health Project Reviews

Any applications for health-related projects will be channeled to the Western Colorado Health Systems Agency for review and comment prior to Committee consideration.

17. Vocational/Technical Projects

All applications for vocational/technical education projects will be channeled through the Coordinating Council for Vocational Education Occupations for review and comment prior to Committee consideration.

18. Councils of Governments

Applicants are encouraged to utilize their area Council of Governments to assist in the preparation of impact applications, review of alternative funding sources, and general impact mitigation activities.

19. Seed Money

The Committee encourages projects that request seed money to provide a service that will later be funded locally.

20. Minimum Level of Service

Because of the limited funds available for distribution, impact funds will be used primarily to assist an area in developing a minimum level of service.

21. State Agency Applications

State agency applicants for impact funds are encouraged to follow these guidelines:

A. The project should be a locally identified need which has been prioritized by a local impact team.

B. State agencies are encouraged to have a local government sponsor for the project.

C. The project should provide a specific level of service which would not otherwise be available or could not continue without impact assistance funds.

D. State agency funding should generally be limited to the next State budget cycle when the agency can incorporate the project into their State budget.

E. Capital improvement projects should generally be avoided.

F. State agencies will be required to exhaust alternative sources of funding in the same manner that local applicants do.

G. State agency applicants must follow the same application procedures as local applicants.

D.2 AVAILABLE SOURCES OF PUBLIC FUNDS TO AID OIL SHALE IMPACTED COMMUNITIES

The following is a brief description of programs and agencies which provide funds which are potentially applicable to communities impacted by oil shale development. Most of the funds come from categorical programs with matching fund requirements and are not specifically geared to mitigating the problems of impacted communities. In addition, many of the federal programs are pass-through programs which are administered at the state level.

FEDERAL PROGRAMS

Farmers Home (Fm HA) 601 Impact Assistance Program

Enacted in 1978 as part of the Coal Conversion Act, the program provides funds to energy impact areas experiencing rapid growth as a result of coal and uranium development. Although the program does not address oil shale, it could potentially free up other impact monies which are currently being spent for coal and uranium impacted communities. The program pays for planning and infrastructural improvements to accommodate new housing. In FY 79, the State received $1.4 million and expects to receive $4 to $5 million in FY 80. Funds are distributed to states based on a fixed formula.

USDA - Fm HA

Grant and loan programs for industrial parks and business development.
Low to moderate income housing loans.
Community facility grants and loans to communities under 10,000 population.

Mineral Leasing Act

The sale of federal lease tracts C-a and C-b provided the state with approximately $75 million with which to establish the Oil Shale Lease Fund.

PILT

The Payment-In-Lieu-of Taxes program provides funds to communities which have federal lands. Although unclear at this point, those payments would likely increase with the construction of NOSR 1.

EPA

201 - sewer and sewage treatment plant construction. Funding 75% federal, 15% state, 10% local.
208 - areawide waste treatment planning, emphasis on non-point source pollution. Administered through COG.

HUD

701 - planning grants to communities and regional planning agencies.
Community Development Block Grants - applicability restricted because generally targeted to urban and depressed areas.
Title VII and X New Community Loan Guarantees for water and sewer systems and other infrastructure improvements.
FHA mortgage guarantees.
Section 8 multi-family housing.
Elderly housing assistance.

DOC - EDA

Title III - planning and technical assistance.
Title IX - targeted to areas of high unemployment for new jobs creation.
Public Works.

DOI

BOR grants.
Land and Water Conservation Funds.
Mineral Leasing revenues.

DOT

Federal highway trust fund.
Monies to state highway departments.

HEW

Title XVI health facilities construction. Medical assistance programs, drug abuse, child abuse, alcoholism and mental health programs.

DOL

CETA
Indian Employment.

DOJ

LEAA - block grants for variety of law enforcement problems.

Federal Regional Council

Supplies coordination and pooling of funds from different federal agencies with State.

STATE PROGRAMS

Many state agencies operate as pass-throughs for federal funds such as for sewers, water, highways, health facilities, housing, etc. State assistance to communities is coordinated and facilitated by the State Impact Office. In addition, the Joint Review Process, which is being experimented with for the Amax Mt. Emmons project may be applied to other large scale mineral development projects and assist in permit coordination, more timely review, and more comprehensive review of impacts and funds available for mitigation.

In addition to the categorical grant programs which can address specific energy impact problems, the State has several programs designed to address a range of problems for which traditional funding sources are either inappropriate, inadequate, or involve lead times which are too long. The two principal sources of impact assistance for oil shale development are the Oil Shale Lease Fund and the Mineral Lease and Severance Tax Fund.

Oil Shale Lease Fund

As described previously, the Oil Shale Lease Fund was established with the revenues from the sale of federal oil shale lease tracts in Colorado. Each year the Joint Economic Committee of the State Legislature reviews the requests compiled by Local Impact Teams, with the assistance of the regional COG's and State Impact Office, in order to determine which projects will receive funding from the Lease Fund. The attached exhibits present a status report of the funds available and the projects which have been funded to date.

Mineral Lease and Severance Tax Fund

According to the Colorado Severance Tax, 20% of severance tax revenues derived from oil shale will be allocated to the Local Government Severance Tax Fund (40% to General Fund and 40% to the Perpetual Severance Tax Fund). The severance tax on oil shale does not become operative until a developer is operating at 50% of design capacity and the first 15,000 tons/day extraction are exempt from the tax. The tax will be assessed at the rate of 4% of gross proceeds and phased in over a four year period. Although money for oil shale impacted communities will be available from the Local Government Severance Tax Fund, specific revenues from oil shale will not be generated until several years after the major impacts have occurred. In order to address this problem, the Legislature passed House Bill 1523 in 1979. The bill allows the operator of a new mining operation a credit against severance tax liabilities in an amount equal to the value of approved contributions by the taxpayer made prior to first severance to assist in solving impact problems of units of local government resulting from the initiation of new mining operations.

EXHIBIT D-1

OIL SHALE LEASE FUND SUMMARY

RECEIPTS

Date	Source	Amount
August 1974	Federal government	$ 24,607,020
August 1975	Federal government	24,607,020
August 1976	Federal government	24,607,020
July 1, 1975-June 30, 1976	Interest	2,658,617
July 1, 1976-June 30, 1977	Interest	3,811,271
July 1, 1977-June 30, 1978	Interest	4,219,969.62
July 1, 1978-Dec. 31, 1978	Interest	2,732,648.25
	Total	$ 87,243,565.87

EXPENDITURES

Year	Appropriated	Expended	Outstanding Commitments
FY 1975	$ 451,187	$ 325,926	None
FY 1976	10,385,3o0	10,029,381	$ 2,000
FY 1977	4,239,646	3,283,408	47,332
FY 1978	6,464,793	4,702,737.49	993,510.07
FY 1979	8,929,090	2,582,108.88	6,262,879.97
Recommended	15,000,000		
Totals	$ 45,470.026	$ 20,923,561.37	$ 7,304,722,04

CURRENT FUND BALANCE

	$87,243,565.87	Total receipts (through December 31, 1978)
minus	20,923,561.37	Expenditures through December 31, 1978
minus	7,305.722.04	Outstanding commitments
	$59,014,282.46	

PROJECTED FUND AVAILABILITY - rough estimate

End of FY 1980 (June 30, 1980) -- $56,557,599.92*

*based on: projected monthly interest earnings of $455,441; full expenditure of FY 76, 77, and 78 appropriations; and, historic average of expenditures to appropriations at the end of the fiscal year of 73 percent applied to the FY 79 & 80 appropriations.

EXHIBIT D-2

OIL SHALE LEASE FUNDS

Awards by County

	AWARDS	AMOUNT
Rio Blanco County	23	$ 11,885,711
Garfield County	31	8,460,735
Mesa County	18	3,831,646
Moffat County	15	3,311,313
Routt County	9	1,108,000
Delta County	2	42,000
Jackson County	1	15,000
Colorado West Area Council of Gov'ts.	5	356,281
Office of the Governor	7	634,079
CWCB (unallocated)	1	600,000
Region XI School Fund (unallocated)	1	100,000
Total		$ 30,344,765

EXHIBIT D-3

OIL SHALE LEASE FUND DISTRIBUTIONS
FY 1975

Total Appropriated $451,187

RECIPIENT		APPROPRIATED
Meeker Schools		$ 4,000
Rio Blanco County Planning		10,000
Garfield Re-1		8,000
Garfield Re-2		12,389
Garfield County Planning		10,000
Mesa Re-51		42,575
Mesa Re-49JT		7,260
Mesa County Planning		10,000
Moffat Re-1		31,000
Colorado West COG		781
Office of Governor		
	Administration	87,187
	State Impact Report	92,734
	TOTAL	$325,926

* 121,261 Returned to Fund

EXHIBIT D-4

OIL SHALE LEASE FUND DISTRIBUTIONS

FY 1976

Total Appropriated $10,385,310

RECIPIENT	APPROPRIATED
Oil Shale Coordinator's Office	$ 100,000
Technical Assistance Region XI COG	200,000
RE-51, Mesa	400,000
Re-49, Mesa	36,000
Roan Creek Road	467,595
DeBeque Bridge	299,658
RE-2, Garfield	1,000,000
RE-16, Garfield	121,057
RE-1, Garfield	200,000
Rulison Bridge	471,000
RE-1, Rio Blanco	1,189,000
RE-4, Rio Blanco	10,000
Piceance Creek Road	1,873,091
Bonanza Road	497,909
RE-1, Moffat	670,000
Hayden Streets	50,000
Routt County Road	100,000
Water Construction Fund-CWB	2,700,000
TOTAL	$10,385,310

EXHIBIT D-5

OIL SHALE LEASE FUND DISTRIBUTIONS

FY 1977

Total Appropriated $4,239,646

RECIPIENT	APPROPRIATED
Oil Shale Coordinators Office	$ 106,000
Region XI COG	25,000
Delta County	17,000
Garfield County Planning	100,000
New Castle Sewer Planning	6,666
Silt Sewer Planning	6,666
Mesa RE-49	147,000
DeBeque Sewer	15,000
Roan Creek Road	665,858
Craig Water Tank	215,000
Craig Hospital	230,000
RE-1 Moffat Leases	51,456
Mental Health	34,000
Rangely Sewer	460,000
Piceance Creek	2,135,000
Hayden School Site	25,000
TOTAL	$4,239,646

* Reduced by $8,174 credit to Piceance No. 2 project, recorded in April 28, 1978 DOH billing to SEIO

** Increased by $8,174 credit to Piceance No. 2 project, recorded in April 28, 1978 DOH billing to SEIO

EXHIBIT D-6

OIL SHALE LEASE FUND DISTRIBUTIONS

FY 1978

Total Appropriated $6,464,793

RECIPIENT	APPROPRIATED
Oil Shale Coordinator's Office	$ 114,079
Region XI COG Planning	62,500
Rangely Streets	500,000
Rangely Sewer	100,000
Meeker Streets	435,400
Meeker Hospital	30,000
Moffat County By-pass	250,000
Craig Drainage	25,000
Craig Water	125,000
Craig City Hall	275,000
Moffat-Sunset School	450,000
Moffat-Modular Rooms	74,000
Mental Health Center	95,857
Grand Valley Bridge	532,125
Garfield RE-2	273,757
Carbondale Sewer	479,000
Carbondale Mun. Building	75,000
Rifle Sewer	438,750
Rifle Lift Station	66,825
Rifle Planning	10,000
Silt Planning	6,500
Mesa RE-51	350,000
DeBeque Water	608,000
Roan Creek Road	135,000
Delta County Water	25,000
Hayden Water	280,000
Hayden Elementary School	450,000
Hayden Drainage	41,000
Hayden Recreation	20,000
Oak Creek Water	122,000
Walden Water	15,000
TOTAL	$6,464,793

EXHIBIT D-7

OIL SHALE LEASE FUND DISTRIBUTIONS
FY 1979
Total Appropriated $8,929,090

RECIPIENT	APPROPRIATED
School Fund	$ 100,000
CWCB	600,000
Coordinator's Office	114,079
Rangely Streets	900,000
Meeker Streets	320,000
Meeker Pool	350,000
Meeker Sanitation	368,000
Impact Coordinator	17,500
Rangely Hospital	50,811
CNCC Facilities	110,000
County Road 24	1,000,000
Garfield Airport	260,000
Rifle Water	2,056,000
Silt Water	151,000
Silt Planning	15,000
New Castle Water	196,000
Grand Valley Water	250,000
Rifle By-Pass	500,000
Mesa County Sewer	104,450
Fruita Sewer	200,000
Mesa County Transportation	25,000
Mesa County Airport Water	293,250
Craig High School	750,000
Region XI Transportation	198,000
TOTAL	$8,929,090

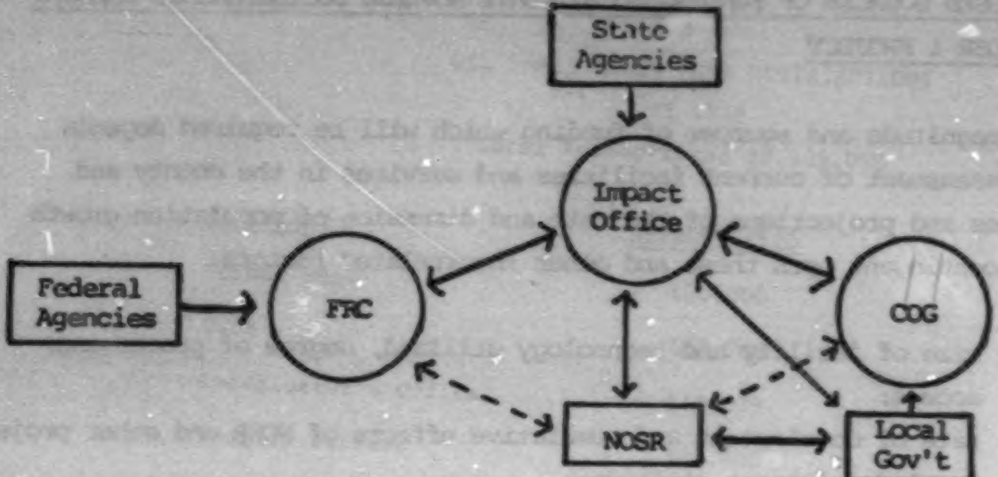
D.3 PROPOSED SOURCES OF FUNDING TO MITIGATE ADVERSE SOCIOECONOMIC IMPACTS OF NOSR 1 PROJECT

The magnitude and sources of funding which will be required depends upon an assessment of current facilities and services in the county and communities and projections of the rate and dimension of population growth which is contingent upon these and other interrelated factors:

1. size of facility and technology utilized, degree of processing;
2. access;
3. rate of development and cumulative effects of NOSR and other projects;
4. local development attitudes;
5. extent of direct federal support;
6. local employment and training programs; and
7. new federal/state programs.

The specific package of assistance programs must, therefore, be contingent upon the resolution of basic questions on the exact parameters of the project. Once there is reasonable certainty with regard to these parameters, the optimal means of providing impact assistance would be through the coordination of each level of government by one agency and overall coordination exercised by the State Impact Office. Coordination within each level of government will result in more efficient, non-duplicative delivery of services and the possibility of joint, coordinated agency projects. At the federal level, the Federal Regional Council (FRC), which has a history and desire to assist in impact assistance coordination, should be assigned the responsibility of coordinating federal agency programs and assistance. At the local level, the COG's have provided valuable technical assistance and support to local impact teams. Finally, the State Impact Office has a responsibility of coordinating state assistance efforts. The proposed interaction would look something like the following diagram.

READEX FICHE



Federal Funding Sources

The principal sources of non-categorical federal funding are the federal lease payments of which 50% are passed on to the State to create the Oil Shale Lease Fund. In addition, monies from PILT and the possible passage of the Energy Impact Assistance Bill in Congress might be available in the next few years. All of the categorical programs listed in the previous section are potentially applicable depending on specific identified need. The federal programs which have been particularly useful to impact communities in the past are those in EDA, Fm HA, LEAA, and the Four Corners Regional Commission.

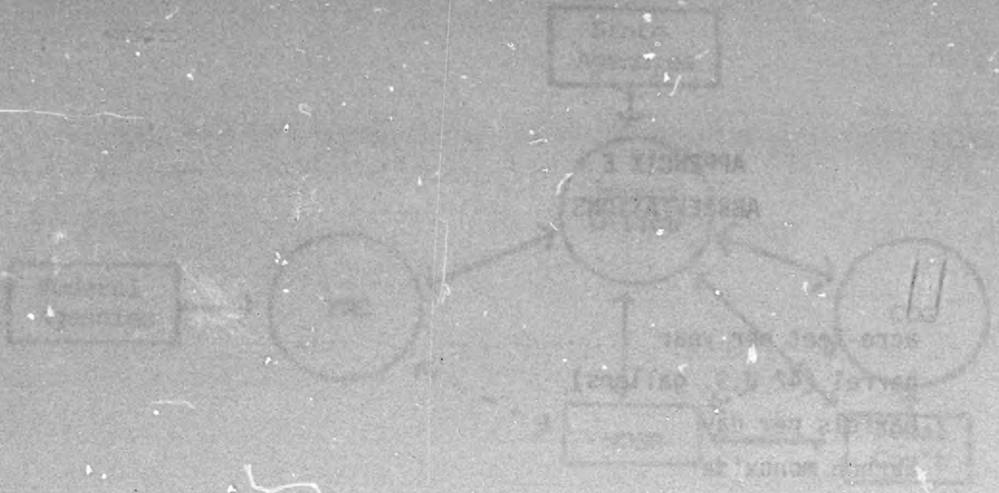
State Funding Sources

The major State funding sources will be the Oil Shale Lease Fund and the Severance Tax Trust Fund. It is unlikely that these funds will provide enough assistance with a major development effort to prevent undesirable disruption. State categorical funding sources and priorities will be determined and coordinated by the State Impact Office. To the extent that state categorical programs are applicable for impact assistance, they will be available for use.

APPENDIX E

ABBREVIATIONS

AF/Y - acre-feet per year
bbl - barrel (42 U.S. gallons)
BPD - barrels per day
CO - carbon monoxide
DOE - Department of Energy
EIS - environmental impact statement
EOR - enhanced oil recovery
GOCO - government owned, contractor operated
HC - hydrocarbons
Mwh/D - megawatt-hours per day
NA - non-attainment
NO_x - nitrogen oxides
NOSR - Naval Oil Shale Reserves
OCS - outer continental shelf
PILT - payment in lieu of taxes
PSD - prevention of significant deterioration
SCF/D - standard cubic feet per day
SO_2 - sulfur dioxide
TPD - tons per day
U-a, U-b - federal prototype oil shale lease tracts in Utah



Federal Funding Sources

The principal sources of non-categorical Federal funding are the Federal lease payments of which 50% are passed on to the State to create the Oil Shale Lease Fund. In addition, [illegible] and the possible passage of the Energy Impact Assistance Bill in Congress [illegible] available in the next few years. All of the categorical [illegible] section are potentially applicable depending on specific identified need. The federal programs which have been [illegible] impact communities in the past are those of [illegible] and the Four Corners Regional Commission.

State Funding Sources

The major State funding sources will be the Oil Shale Lease Fund and the [illegible] Trust Fund. It is unlikely that these funds will provide [illegible] with a major development effort to prevent undesirable [illegible]. State categorical funding sources and priorities will be determined and coordinated by the State Impact Office. To the extent that State categorical programs are applicable for impact assistance, they will be available for use.

APPENDIX F

COMMENTS ON DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT
DOE/EIS-0068
DATED SEPTEMBER 1980

This appendix contains copies of all letters received on the Draft Programmatic EIS, transcripts of the public hearings held in Grand Junction and Denver, and DOE responses to the comments raised in each. Letters were received from 21 public agencies and private organizations and there were three public meetings. Each letter and hearing transcript, listed below, is coded by number. Each is considered a set of comments. Individual comments are coded within sets for reference purposes.

Colorado	Set 1	Dept. of Natural Resources (Deputy Director)*
	Set 2	Dept. of Natural Resources (Energy Policy and Planning)
	Set 3	Dept. of Natural Resources (Executive Director)
	Set 4	Dept. of Local Affairs (Division of Planning)
	Set 5	Office of Energy Conservation
	Set 6	Dept. of Highways
	Set 7	Historical Society
	Set 8	Dept. of Natural Resources (Division of Wildlife)
	Set 9	Dept. of Health
	Set 10	Energy Research Institute
Federal	Set 11	Environmental Protection Agency
	Set 12	Dept. of Interior
	Set 13	Dept. of Interior (Bureau of Land Management)
	Set 14	Dept. of Interior (Bureau of Mines)
	Set 15	Dept. of Housing and Urban Development

* Specific comments attached to the letter identified as Comment set 1 were also included as a part of Comment set 2 and are reproduced and responded to only in Comment set 2.

Other Public and Private Institutions	Set 16 Sierra Club
	Set 17 National Wildlife Federation
	Set 18 Friends of the Earth
	Set 19 Rio Blanco Natural Gas Co.
	Set 20 Philips Petroleum Co.
	Set 21 Occidental Oil Shale Inc.
Public Hearings	Set 22 Grand Junction (11/18/80, 2:00 PM)
	Set 23 Denver (11/20/80, 2:00 PM)
	Set 24 Denver (11/20/80, 7:00 PM)

STATE OF COLORADO   RICHARD D. LAMM, Governor

DEPARTMENT OF NATURAL RESOURCES

D. MONTE PASCOE, Executive Director
1313 Sherman St., Room 718, Denver, Colorado 80203 839-3311

Board of Land Commissioners
Division of Administration
Division of Mines
Division of Parks & Outdoor Recreation
Division of Water Resources
Division of Wildlife
Geological Survey
Oil and Gas Conservation Commission
Soil Conservation Board
Water Conservation Board
Mined Land Reclamation

DM

DEAN MASSEY
X6922

December 2, 1980

Captain Gordon Gilmore
U. S. Department of Energy
Naval Petroleum & Oil Shale Reserves
Room 3344, Federal Building
Washington, D. C. 20461

Dear Captain Gillmore:

We want to commend your office for undertaking a comprehensive review of alternatives to development of the Naval Oil Shale Reserve in the programmatic DEIS. The comparative analyses of alternative energy sources is certainly ambitious and can contribute vitally important information to a thorough assessment of requirements and potential for energy development in Colorado as well as the nation. Naturally, we are especially concerned about oil shale development in the Piceance Basin and anxious that it occur in an environmentally and socially responsible manner.

We do have some problems with the DEIS. We believe that these problems may be significiant enough for us to request that DOE rewrite the DEIS. However, before we make a formal request to that effect, it would be useful for us to discuss with representatives of TRW, Inc., consultants to DOE and principal authors of the DEIS, certain basic questions we have on the analyses. Answers to these questions will be very helpful to us in determining how our comments can be most constructive. A list of a few preliminary questions is enclosed. They are concerned with data sources, assumptions, and methodologies used in the analyses and with the use of the DEIS as a resource management decision tool.

As you know, we expected to meet with TRW on November 20 in Denver. We appreciate that contractual difficulties with TRW are severely limiting their participation in the current discussion of the DEIS. Lee Brennan offered to have TRW meet with us as soon as DOE's legal problems with TRW are resolved. We accepted his offer and look forward to meeting with TRW and your staff in the near future. I am sure that you can readily understand our desire to clear up these essential questions on the DEIS prior to making our final comments. I do not anticipate that answers to these questions are particularly difficult; they are just not available to us. We are formally requesting an extension of the comment period for the State of Colorado from December 15, 1980, until we have met with TRW, discussed our questions, and compiled our comments. Donald Silawsky has offered to convey the initial list of questions to TRW during the interim so that we can get the ball rolling.

The November 20 meeting with your staff was very useful in spelling out our respective positions on NOSR and how we propose to approach future NOSR activities and decision points. It was agreed at the meeting that a NOSR team composed of appropriate representatives from state and federal agencies be assembled as soon as possible to advise DOE on management and development decisions for NOSR based on their review of available information. We anticipate the team meeting in the near future to review the decision options which are outlined in the DEIS. David Kunts of our office and Donald Silawsky of your office are responsible for making the specific arrangements.

We are looking forward to a good working relationship with your office on NOSR. Colorado's participation in federal energy development decisions is critical if DOE is to have an accurate assessment of the potential cummulative impacts from current, proposed, and projected energy developments in the state and of the implementation of appropriate mitigation strategies.

I would appreciate your response to the timing of a meeting with TRW and submission of our final comments. I hope that the current difficulties can be speedily resolved so that we can better advise you on the course of energy development on the NOSR.

Sincerely,

Hamlet J Barry

Hamlet J. Barry, III
Deputy Director

HJB:mc

STATE OF COLORADO RICHARD D. LAMM, Governor

DEPARTMENT OF NATURAL RESOURCES

Monte Pascoe - Executive Director
1313 Sherman St., Room 718, Denver, Colorado 80203 839-3311

Board of Land Commissioners
Division of Administration
Division of Mines
Division of Parks & Outdoor Recreation
Division of Water Resources
Division of Wildlife
Geological Survey
Oil and Gas Conservation Commission
Soil Conservation Board
Water Conservation Board
Mined Land Reclamation

December 3, 1980

Mr. Donald Silawsky, Environmentalist
Office of Naval Petroleum and Oil Shale Reserves
Resource Applications
Department of Energy
Room 3344, Federal Building
Washington, D.C. 20461

Dear Don:

I want to thank you for meeting with us a couple of weeks ago. I thought the meeting was useful in spelling out our respective positions on NOSR and how we propose to approach future NOSR activities and decision points. To get the ball rolling between TRW and us, I am enclosing a list of preliminary questions which I would like you to pass on to the appropriate TRW people. As we discussed earlier, answers to these questions would be helpful prior to submission of our comments on the DEIS. Hamlet J. Barry, Deputy Director of the Department of Natural Resources, has written a letter to Captain Gordon Gilmore formally requesting extension of the comment deadline for the State of Colorado from December 15, 1980, until such time that we have met with TRW, discussed our questions and compiled our final comments. Our questions are rather basic in nature and I do not anticipate them being particularly difficult to answer. Certainly, the TRW impasse should not interfere with the establishment of a productive working relationship between our offices. I appreciate your cooperation on this matter and look forward to clearing up the TRW issue quickly once the legal problems are resolved.

We also need to discuss as soon as possible the best arrangement for setting up the "NOSR team" which we talked about at the November 20th meeting. We believe such a team would be a useful forum for ensuring an active state role in NOSR development and management decisions. The team can reduce the potential for surprises from either end by keeping members aware of each other's plans, programs, and policies in a timely manner. The purpose of the team would be strictly advisory on NOSR policy to the Director of the Naval Petroleum & Oil Shale Reserves and through him to the Secretary of Energy. The team would not involve itself in operational matters on NOSR unless specifically requested to do so by your office. For the time being an informal arrangement for the NOSR team is agreeable to us. We recognize the difficulties inherent in the Federal Advisory Committee Act and do not think it is necessary to structure the team's format under the Act at this time.

I recommend three official members on the team: a representative of DOE, a representative of the Governor of Colorado, and a representative of the Garfield County Commissioners. Other federal, state, and local agency representatives could serve the team in an ex-officio capacity as needed or requested by team members. The meetings would be public meetings held prior to all key decision points with opportunities for public participation and comment. DOE would be responsible for the agenda and chairing the meetings. Information relevant to the decisions would be distributed to team members prior to the meetings and form the basis for discussion and subsequent recommendations. I envision the team acting by consensus, but with the opportunity for dissenting opinions to accompany team recommendations. I believe this proposal has enough flexibility that we can adopt it to meet our needs. I would appreciate your reactions to this proposal and any additional ideas or suggestions you have for implementing a cooperative state-federal effort on NOSR decisions.

I am looking forward to working with you in the future. I thought the meeting we had was particularly useful in laying the groundwork for designing a cooperative approach for decision making on the NOSR tract. Please let me know where we stand from your end on the proposals and what remains to be done to get them in place.

Sincerely,

Dave

David Kuntz
Energy Policy & Planning

Some of the questions to which the State of Colorado needs answers prior to making final comments on the NOSR DEIS include the following:

- NET ENERGY ANALYSIS

2-1

Assumptions and methodologies used in net energy analysis and cycle efficiency.

1) Is only the processing stage of oil shale production included?

2) Why haven't the extractions, crushing, refining, and distribution to the end user been included in the analysis.

3) It appears that only fuels in and out are compared and indirect or invested energy is ignored.

Quantities and types of invested energy vary so much among alternate energy sources, a comparative assessment should be based on a true net energy analysis and not on a simplistic I/O model; the DEIS should not claim to have any definitive energy efficiency information as it stands. We will suggest various, more comprehensive net energy analysis models in our final comments.

- DATA SOURCES

2-2

Use of the 1975 University of Oklahoma study: Energy Alternatives-A Comparative Analysis. The efficiency given in the NOSR DEIS for Tosco II/Room and Pillar is 79%. The Oklahoma study gives an efficiency rating for Tosco II of 66.7%-why is there a discrepancy? The Oklahoma study questions the 66.7% figure as being too high (66.7% figure came from a study done by Hittman Associates). What are the reasons for using the Oklahoma study as a reference?

- END PRODUCT USE

2-3

1) What is the projected end use of oil shale from NOSR?

2) Have market analyses been performed for end product use? Transportation methods, corridors?

2-4

3) If end product is gasoline, then why has reduction in vehicle weight been the only scenario considered in the conservation alternative? A better, more detailed approach would analyze the total potential savings in transportation from increased mass transit, car pooling, etc.

4) If the end product is not gasoline, then why is energy conservation in the transportation sector (specifically light duty vehicles) considered as the alternative?

o CONSERVATION ALTERNATIVE

2-5 Energy conservation is described as advantageous in reducing air pollution. Conservation impacts on water requirements, land use, water quality, and socio-economic factors are not analyzed. What are the constraints on a more comprehensive analysis of the energy conservation alternative?

o PURPOSE

2-6
1) What is the purpose of the DEIS?
2) How will the EIS aid in decisionmaking?

o CONCLUSIONS

2-7
1) What action is the EIS recommending? preferred alternative?
2) Alternatives are compared in the analysis, in the various tables and graphs of section 3; why weren't conclusions drawn as to the preferred alternative?
3) Based on the analysis, why isn't the energy conservation alternative the preferred alternative?

o MITIGATION OF IMPACTS

2-8 No baseline carrying capacity variables.

No discussion of viable mitigation strategies. Given the magnitude of the impacts resulting from oil shale development, the EIS needs a comprehensive discussion of how these impacts will be mitigated, who is responsible for the mitigation, and how much the mitigation will cost.

The cumulative impacts in the region are not adequately discussed. Although the impact increment contributed by NOSR may be relatively small, it has to be examined in light of the carrying capacity of the region.

o LOCAL

2-9 Were local governments and regional planning agencies consulted when the socio-economic analysis was performed?

o TRANSPORTATION

2-10(A) 1) Secondary transportation impacts

2-10(B) 2) Product haul-where marketed, how transported

o ROUGH TERRAIN MODELING

2-11 Air pollution potential

RESPONSE SETS 1 AND 2

(Comment sets 1 and 2 are responded to jointly since they raise almost identic issues)

2-1 Cycle efficiency considered mining, transportation within the mine, crushing, transportation outside of the mine, retorting and upgrading of the shale oil. Indirect energy was not considered because it contributes only a small fraction to the net energy analysis. Refining and distribution to the end user were not included because shale syncrude will be a direct substitute for imported crude oil, yielding essentially no change in energy requirements. The energy analysis has been extended to secondary and tertiary energy requirements, and there is no appreciable change in the final result (see Appendix C). Secondary and tertiary contributions are less than the uncertainty associated with the primary energy requirements.

2-2 The wrong reference was cited for the 79% figure. The correct reference is Oil Shale Data Book, TRW for U.S. Department of Energy, June, 1979. The data contained in this reference were supplied by TOSCO and confirmed by TRW and other engineering team members. They reflect the latest information available and supersede the University of Oklahoma figures of 1975.

2-3 The projected end use of shale oil is as a refinery feedstock. A "Marke Assessment for Shale Oil" (DOE/E-T-2628/1) was done for the Dept. of Energy in October 1979 by Pace Consultants and Engineers. At the time development is proposed, current market studies will be conducted.

2-4 Gasoline is only one of the possible fuel products from refining shale oil. As was stated on pages 3-1 and 3-2 of the EIS, a representative case for each alternative, which could meet the criteria listed, was chosen. Weight reduction was the case selected. It results in quantifiable reductions in fuel usage and does not attempt to impose lifestyle changes. Mass transit, car pooling, and other similar measures introduce the uncertainty of the population's response and cannot be as accurately quantified. The rationale is explained on page 3-4.

2-5 Given the definition of the conservation alternative employed, reduced vehicle weight and improved fuel efficiency, conservation impacts on water requirements, land use, solid waste and socioeconomics were not expected to be significant. It was assumed that proposed automotive design changes would be accommodated in annual model year changes, which are standard procedure in the auto industry. Primary effects on water, land, solid waste and socioeconomics would therefore be minor. Although it is possible that reduced vehicle weight would change requirements for materials used in automobile manufacture, which would in turn affect the industries supplying these materials, representing secondary and tertiary changes becomes more uncertain. To estimate water requirements, land use, solid waste and socioeconomic effects would require making increasingly tenuous assumptions about secondary (e.g., reduced materials demand) and tertiary (e.g., potential reduction in jobs in materials industries) impacts related to vehicle weight. To make these assumptions for the conservation alternative is neither desirable nor necessary for the purpose of the NOSR programmatic EIS since secondary and tertiary effects are also expected to be minor and the relative merits of conservation vis-a-vis the other alternatives have been indicated.

Also see response to comment 5-1(G).

To perform a more comprehensive analysis of the conservation alternative is, in our opinion, not necessary for the reasons stated above. However, in order to avoid confusion, the text has been clarified to indicate that the conservation alternative would not have adverse water or land requirements or production of solid wastes, and that socioeconomic effects would be minimal.

2-6 The draft EIS did not clearly explain the NEPA compliance program DOE developed for the proposed development of NOSR 1, nor was the role of the programmatic EIS in this compliance program clearly discussed. A new subsection in Section 2, entitled "The Purpose of this EIS," has been included to remedy this deficiency.

2.7 The draft EIS was unfortunately vague in setting out the specific action being proposed and the purpose of this proposal. Section 2 in the final EIS, "The Proposed Action and Its Purpose," has been extensively revised to provide a clearer explanation. Similarly, the draft EIS did not clearly indicate a preferred alternative, although there was some brief reference on page 1-2 of the draft to a preferred alternative of "no action." Section 3, "Alternatives and Comparisons," has been revised with a new subsection on the "Preferred Alternative."

A number of comments were received which questioned why conservation was not the preferred alternative, on the basis that there were virtually no adverse environmental impacts associated with the alternative of "producing" (by not using) liquid fuels. The presently preferred alternative, "no action," also has negligible adverse environmental impacts. Federal policy is to meet the nation's energy needs from a variety of sources, through both production and conservation, as dictated by market forces. It should be noted, as a reading of the revised Section 2 will show, that the option of developing NOSR 1 is unique in one respect, due to the priority uses set out for its fuel products by the various Executive Orders regarding the NOSRs issued in the early 1900s. While a national program of conservation could save a quantity of liquid fuel products equal to the quantity which could be producted from a NOSR 1 oil shale project, Government control over this quantity would be almost nil in the conservation case, but virtually complete in the NOSR case. Because of the unique status of NOSR 1 as a military reserve, the Government can do certain things with the production from NOSR 1 which it cannot do as easily, or at all, with production from other liquid fuel sources, especially conservation. For these reasons, conservation is not the preferred alternative.

2.8 The subjects of baseline carrying capacities, cumulative impacts and mitigation measures were discussed in the draft EIS, but in a somewhat disjointed manner. The final EIS contains two separate subsections in Section 5 on cumulative air quality and socioeconomic impacts. Section 4, "Description of the Affected Environment," has been revised to provide additional details on baseline carrying capacities, and the discussion of appropriate mitigating measures has been enhanced in Section 5 and in Appendix D. Even these revisions may not, however, completely satisfy the requests of a number of respondents for highly detailed cumulative impact analyses. DOE acknowledges, and shares, their concern, but believes, for a number of reasons, that this final EIS is not the appropriate vehicle for the type of detailed cumulative impact analyses they requested. If in fact the Department was still actively considering the development of NOSR 1, then our response on the cumulative impact question would have been quite in line with most of the comments regarding this issue. However, the Secretary has decided that NOSR 1 should not be developed at this time. Development of NOSR 1 is not contemplated at least for the present. To conduct these detailed, and costly, modeling exercises for cumulative impacts now, but to hold off making the decision to develop NOSR 1 until a few years in the future, simply guarantees that the "stale" information would have to be updated all over again. DOE does not believe that this is a prudent use of our budgetary resources, and we would hope the respondents who commented on the cumulative impact analysis in the draft EIS would agree. The Department is firmly committed to a vigorous and effective environmental compliance program for the NOSR project, but this program must also be efficient in its use of personnel and budgetary resources. When the NOSR 1 development question is revisited at some future data, all available data regarding cumulative impacts in the rapidly-changing Western Slope region will be evaluated, and appropriate steps taken to ensure that the development decision process is adequately supported by the best available data, which could include new modeling and analyses efforts by the Department. In addition, the Department of the Interior (DOI) is preparing a programmatic EIS on its oil shale leasing program. This EIS will contain information of the type requested by various commenters regarding the cumulative impacts of oil shale development in the Piceance Basin region.

2-9 The following governmental units and planning agencies were contacted during the preparation of the draft statement: The Colorado Department of Local Affairs, Division of Energy and Mineral Impact Assistance; the Colorado West Area Council of Governments; the Colorado Division of Planning, and the Cities of Rifle and Parachute.

2-10A See response to comment 6-1.

2-10B There are currently two major schools of thought on the geographical markets for shale oil. One school favors pipelining shale oil to the Texas/Louisiana refinery complexes, which are the hub of the nation's product pipeline network. Refined fuels would then go to the market areas traditionally served by these product pipelines. The second school favors pipelining the shale oil to the midwest, St. Louis, Chicago and Detroit. The shale would be refined and used in this region. Both schools of thought believe some portion of the shale oil will be refined and used in the Rocky Mountain region. At the time development is proposed, current market studies will be conducted.

2-11 Refer to the response to comment 2-8.

STATE OF COLORADO RICHARD D. LAMM, Governor

DEPARTMENT OF NATURAL RESOURCES

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1313 Sherman St., Room 718, Denver, Colorado 80203 839-3311

Board of Land Commissioners
Division of Administration
Division of Mines
Division of Parks & Outdoor Recreation
Division of Water Resources
Division of Wildlife
Geological Survey
Oil and Gas Conservation Commission
Soil Conservation Board
Water Conservation Board
Mined Land Reclamation

December 18, 1980

Captain Gordon Gilmore
U.S. Department of Energy
Naval Petroleum and Oil Shale Reserves
Mail Stop Room 3344, Federal Building
Washington, D.C. 20461

Dear Captain Gilmore:

This letter, together with its attachments, comprises the preliminary comments of the State of Colorado on the Draft Programmatic Environmental Impact Statement on development of the Naval Oil Shale Reserve in Colorado. As noted in my deputy's letter of December 2, we have accepted your invitation to meet with the contractor who prepared the DEIS and may make additional comments after that meeting.

We commend your office for undertaking an ambitious and important effort of comparing alternative energy sources with the possible development of the shale resources of NOSR. A comparative assessment of shale and other alternative technologies is long overdue and can make valuable contributions to decisions on how, where, and when federal actions are needed to make adequate liquid fuel available to meet the nation's energy needs.

However, it appears to us, at this point in our analysis, that serious questions can be raised about the adequacy of this draft. Specifically, there appear to be four major flaws in the draft's comparison of NOSR with other liquid fuel alternatives:

-1 o The EIS focuses on specific technologies which may be inappropriate comparisons with NOSR development. The EIS could have considered indirect coal liquefaction rather than direct liquefaction, possibly biomass conversion from crop residues rather than a single massive corn-based plant, and a range of shale technologies rather than the Colony project.

3-2 o The comparisons between the alternatives appear to be incomplete. Some alternatives involve the production of crude oil (or syncrude); other alternatives involve the production (or conservation) of highly refined product. Some alternatives are defined to include the extraction or mining; others include only processing or refining. The result is an incomplete and possibly misleading comparison between the alternatives with respect to water requirements, air emissions, socio-economic impacts, net energy balences, and other factors.

3-3 o Major impacts of NOSR development are given inadequte or only sketchy treatment in the EIS. Examples are the availability of front-end funding for public infrastructure in the oil shale region, reclamation, wildlife, and vegetation impacts.

3-4 o Data sources are not cited, and there are several apparent inaccuracies in data on impacts. Examples include SO^2 emissions from shale plants, water usage of biomass conversion, capital requirements for shale plants, and others.

These comments are detailed on pages 8-16 of this letter and in the attachments.

DESIGN OF THE EIS

Before turning to these specific issues, some fundamental questions must be raised about the design of the EIS.

3-5 CEQ regulations provide that Environmental Impact Statements shall be written on "major federal actions" and that EISs shall identify the "proposed action" which is triggering the NEPA process. The draft EIS does not clearly identify a proposed action.

The draft lists three DOE decisions to which the document is to provide "input"(1-1):

> (1) Whether to promote development of oil shale on federal land (beyond that presently subject to lease); (2) if the decision is to develop additional federal land, whether to develop the 35,000 acre Naval Oil Shale Reserve No. 1 (NOSR I) in Northwest Colorado; and (3) if the decision is to develop NOSR I, what institutional and financial mechanisms should be selected to develop it.

The first of the three decisions would seem to refer to federal lands currently being administered by the Department of Energy or by the Department of the Interior. However, the draft EIS makes no effort to define proposed actions relating to Interior lands or to analyze impacts of developing these lands. As you are well aware, Interior is currently planning a renewal of leasing of these lands under the prototype leasing programs, as well as the design of a permanent leasing program, and will be preparing the relevant EISs on these actions. We would suggest that the NOSR EIS is not designed to provide input to these decisions and that the first of the three decisions listed above should be dropped from the EIS.

It would be appropriate, however, for Interior and DOE to coordinate their assessment of the need for development of federal oil shale reserves in general -- regardless of whether they are managed by Interior or DOE.

The second decision listed in the EIS refers to the development of NOSR I. The EIS is written as if this were the proposed action. However, on the following page, the "no action" alternative is defined as the "preferred alternative."

CEQ regulations require that the "range of alternatives discussed in environmental impact statements shall encompass those to be considered by the ultimate agency decisionmaker" 40 CFR (1502.2(e)). The draft EIS does not make it clear whether coal liquefaction, energy conservation, biomass, and other non-NOSR alternatives are truly alternatives as defined by the CEQ regulations. The inclusion of non-shale alternatives in this EIS suggests that DOE will consider these alternatives in its decision on NOSR.

However, on page 1-4-5, the draft EIS suggests that these are not really alternatives:

> all such comparisons are useful, (but they) do not lead directly to any conclusions...In this sense they are not true alternatives, with the possible exception of oil shale development on other lands.

Also, on page 1-3, the EIS states that NOSR may be developed "if there is an absence of meaningful oil shale development during the next year to 18 months." This statement suggests that non-shale alternatives will not be considered in deciding whether to proceed with NOSR development.

Ultimately, Congress will decide whether to develop NOSR. However, DOE clearly can and should identify the alternatives which its decision makers will consider in formulating DOE's recommendations to Congress. It would be very helpful if the EIS would clarify what the alternatives are to NOSR development and what decision criteria will be used in weighing these alternatives. This would include a definition of how much shale development is "meaningful", and if the decision about NOSR will be based on the criteria stated on page 1-3.

In defining "meaningful," it may be helpful for DOE to consider Congressional statements, in the Energy Security Act, of goals for synthetic fuel production by 1987 and 1992. It may also be useful to consider President Carter's widely quoted goal of 400,000 BPD of shale oil by 1990. On the basis of the projections we have seen it would appear that industry plans to achieve these goals. Further, most analyses indicate that the most important constraints on production will be the unfavorable economics, massive front-end capital requirements, the availability of electricity, water, and skilled manpower, and cumulative socio-economic and environmental impacts. The availability of adequate land and shale resources is not expected to be a significant constraint on the achievement of synfuel production goals. This suggests that making NOSR available for development will not help very much, if at all, to achieve national synfuel production goals.

The draft EIS' treatment of the "no action" alternative is as confusing and incomplete as its discussion of "meaningful" shale development. The analysis of "no action" seems to be based on the assumption that "no action" means literally that -- that nothing will happen on or near NOSR. The draft EIS treats "no action" in this sense and identifies no impacts from this alternative. Thus the treatment of "no action" is very skimpy, although it is the "preferred alternative."

In fact, DOE is likely to continue certain monitoring and experimental activities on NOSR, and DOE is more likely to take "no action on commercial development of NOSR" if there is a lot of "action" on nearby shale properties in Garfield and Rio Blanco Counties.

The "no action" alternative should therefore include an analysis of the impacts of other energy development in the shale region and of continued research on the NOSR tract.

Clarifying the "no action" alternative would also help with two other problems. First, it might help to define what decision criteria DOE will use to define whether or not there has been enough "meaningful" development so that commercial development of NOSR is required. Second, it might help to clarify how the impacts of NOSR development will interact with the impacts of other developments in the region. As it stands, the draft EIS ignores the issue of cumulative impacts, contrary to 40 CFR 1508.25.

The DEIS also gives relatively little attention to mitigating measures. CEQ regulations require that mitigation be included either as part of the proposed action or in alternatives to the proposed action. It may be difficult, at this early stage in deciding whether or not to develop NOSR, to design specific mitigation plans. But the regulations do require that mitigation be explicitly addressed so that the federal decision-maker may be aware of mitigating measures that are available.

GENERAL METHODOLOGICAL PROBLEMS

3-6 Two methodological problems are evident throughout the DEIS . One is the asssumption that the impacts of producing 200,000 BPD (of shale oil, biomass/alcohol, liquid coal products, or whatever) are four times greater than the impacts of producing 50,000 BPD. Assuredly, it is difficult to pin down the precise values for socio-economic and environmental impacts of higher production levels. However, at some point, the relationship between the severity of impacts and the amount of liquid fuel produced will become non-linear. This is especially true when higher levels of production must be concentrated in a small geographic area; this is the case with oil shale development in the Piceance Basin. The DEIS ignores this reality and thus oversimplifies the analysis.

3-7 The second methodological problem concerns the comparability of the alternatives studied in the DEIS. The draft analyzes shale oil production from mining through processing and production of a product roughly comparable to crude petroleum. The analysis of the shale alternatives does not include upgrading, refining, or transportation of the product. In contrast, the coal liquefaction alternative does not cover the mining of coal or the transport of coal to the liquefaction plant. But the coal liquefaction alternative does cover the production of fuels comparable to refined shale oil products.

The conservation alternative is even less comparable to shale. It covers only refining, distribution, and use of gasoline; it omits the drilling of wells and transport of the product to refineries.

This lack of comparability between the alternatives may well skew the whole analysis by omitting significant impacts. As one example of the problems that may arise, one might consider the comparative analysis of cycle efficiencies in the DEIS. The analysis in the DEIS comes to the conclusion that NOSR-produced shale oil has a much higher cycle efficiency than any other alternative except OCS oil. But this conclusion would appear to be suspect.

3-8 The meaning of cycle efficiency and the methodology used in calculating it are not revealed. We assume that a direct energy I/O method was used; i.e., fuels in and out are compared and indirect or invested energy is ignored. While indirect energy contributions may be relatively small, this simplistic approach misses some important factors which may be unique to certain alternative energy sources. For example, coal mining and transportation to the coal liquefaction or ethanol production plant are omitted in the cycle efficiency calculations. It appears that only the processing stage of oil shale production is included in the cycle efficiency calculation; extracting, crushing, and distribution stages are omitted. A cycle efficiency calculation which does not include major energy input stages of the process is not very useful.

Quantities and types of invested energy vary substantially among alternate energy sources. A comparative assessment should be based on a true net energy analysis. Several net energy analyses exist which can be used to fulfill this need. The Colorado Energy Research Institute's 1976 net energy analysis study is an example of a more thorough treatment of net energy balances (a weakness in the CERI study which needs correction is an analysis of the secondary impacts).

3-9 There is an additional problem with the analysis of cycle efficiency that should be mentioned here, even though it is not directly related to the methodological issue. On page 3-12, the DEIS shows cycle efficiency ratings of 85% for NOSR and 79% for other oil shale. This result is based largely on a 1975 University of Oklahoma study, which shows 66.7% rating for TOSCO II room-and-pillar mining. The reasons for the discrepancies between these figures are not explained in the DEIS.

SPECIFIC COMMENTS ON ALTERNATIVES

We have focused our detailed review of the DEIS on four of the energy sources: oil shale, coal liquefaction, biomass/alcohol, and energy conservation. The following comments represent a synthesis of major issues raised in this review. Please see the appended comments for additional discussion of various aspects of the DEIS.

OIL SHALE

3-10 Emissions. The draft EIS shows signficant differences between the air emissions of NOSR I and of the Colony project. NOSR I emissions for SO_2, NO_x, CO, HC, and TSP are 2-6 times lower than emissions for the other oil shale project (Colony). Although the absence of adequately cited sources makes it difficult to check these numbers, one of the reasons for the discrepancy may be that the source for the Colony projections,(the Colony EIS),was prepared prior to the 1977 amendments to the Clean Air Act. The NOSR I analysis was prepared after the PSD regulations were authorized and assumes more stringent standards, a higher degree of control, and thus, lower emissions. Colony will obviously have to meet the same standards as NOSR.

The Office of Technology's 1980 study, An Assessment of Oil Shale Technologies, contains pollution emission estimates from three different oil shale projects (262-263,.278-279). A comparison of OTA's figures with figures in the DEIS (C-3, C-9) shows that in the NOSR case the DEIS underestimates SO_2 emissions while in the Colony case particulates are overestimated. The discrepancies between the DEIS and OTA air emissions figures are an example of what happens when data from different sources, produced in different years, and based on different states of knowledge, is used to make comparisons. OTA data shows that DEIS air emission estimates for NOSR I generally occur within the bounds of industry estimates (except for SO_2). Colony, however, occupies the high end of the industry range in the OTA data and, thus, may not be the most representative project for the oil shale industry.

3-11 Ranges of estimates would provide a better picture of emissions levels associated with various technologies. Point-specific values for pollutants and other environmental and socioeconomic factors lend a degree of certainty to the analysis which does not exist in the real world.

Capital Costs. Capital costs are a fundamental component in determining the viability of an alternative fuels industry. The DEIS contains several capital cost figures. We are unable to review these estimates adequately due to the paucity of information about data sources and about the assumptions used in deriving estimates.

The DEIS estimates a cost of $1.3 billion per 50,000 bbl/d oil shale facility (3-31, C-2, C-8). This figure is outdated. The source of the cost estimate is not stated; a 1976 study by TOSCO presented the $1.3 billion figure. Is this the source for the DEIS? OTA's more recent estimates are $1.7 billion in 1979 dollars and $2 billion in 1980 dollars (OTA-16). Some industry sources project capital outlays of $3-5 billion per plant before commercial oil shale production is accomplished. The OTA (1980) report also states that no definitive cost data for commercial-size plants exist because none have been built. "Cost estimates for projects have traditionally been unstable, rising by more than 400 percent between 1973 and 1978" (OTA, 1980, 16). Tremendous uncertainties remain about the industry's capability to finance and build oil shale facilities.

3-12

The DEIS encounters similar problems in estimating capital costs for coal liquefaction and alcohol/biomass facilities. The $2.4 billion cost for a 50,000 TPD SRC II plant is much higher than $1.7 billion cost, with a 20% contingency, which is given in the 1979 *SRC II Demonstration Project (2-8)*. While the $1.7 billion cost is based on 1978 dollars, it is not known which year dollars are used in the DEIS. A capital cost estimate based on documents being developed for a commercial SRC II plant of comparable design would be better than combining information from a variety of sources.

Data contained in *Energy from Biological Sources, Vol. II* (OTA, 1980-164) shows that capital costs for a 50 million gallon/year coal-fired distillery would total $64 million (1980), not $58 million as stated in the DEIS. A total investment (fixed capital and working capital) for producing ethanol from grain (corn) requires $70.4 million in 1980 dollars (OTA, 1980, 165).

3-13

Population Estimates and Socio-economic Impacts. The DEIS shows population increase projections of about 1200 operating workers and a total population increase of about 7,000 people for NOSR I (3-24, C-4). Data in the OTA (1980,17) study indicate that the DEIS projections underestimate the population requirements for constructing, operating, and maintaining a 50,000 bbl/d oil shale facility. OTA figures are 1600 operators per plant and a total population increase of 8,800 people. These figures are more in line with our actual experience with the Union and Colony projects. These estimates show that the DEIS underprojects operating worker increases by 25% and total population by 25%. It is unclear what data source is used in the DEIS population projections.

Much of the socioeconomic impact discussion for the NOSR case (5-47-5-52) concentrates on population growth trends during the 1970s (5-48, 5-49) without an adequate assessment of the impact of the population projections from NOSR. The DEIS (5-49) merely states that "the employment and population effects of the NOSR or Colony projects will thus be superimposed on an area already experiencing substantial growth."

However, the figures in the EIS show that NOSR would cause a dramatic acceleration of recent growth rates in the area. The EIS shows that population in Garfield County increased by 4000 between 1970 and 1977. Development of a 50,000 PBD plant at NOSR wuld cause twice as much population growth, probably in less than seven years. The three population centers nearest the NOSR tract which would logically bear the brunt of the impact of development -- Rifle, Silt, and Grand Valley -- have a total population (1980) of 4,768. The rural and unincorporated areas of Garfield County (site of the NOSR tract) have about 12,000 residents. The addition of 8,800 new residents from NOSR to Garfield County will have tremendous impacts. The magnitude of the impacts should be reflected in the adequacy of the analysis.

The DEIS ignores socioeconomc impacts from other energy developments which result in what is commonly known as the "peaking problem." The combination of construction and operation workers on various energy developments and the ancillary population generated by these activities can result in cumulative socioeconomic impacts of enormous proportions. The increment which these impacts will add to an already expanding population is unknown. These impacts will have to be absorbed by a region which the Colorado West Council of Governments projects will more than double in population during the 1980s.

The DEIS states (p. 3-23) that adequate planning and preparation, including the development of new towns, can help to alleviate adverse socioeconomic impacts. On the following page, the chart indicates that impacts of the Colony project will be mitigated by a "new community."

3-14 The DEIS does not contain any discussion of whether development of NOSR would entail assistance to local planning or the development of a new town. Also, the DEIS does not mention the fact that the new town for the Colony project is likely to house only 50% of the workforce for that project. Nor is there discussion of the fact that the development of a new community may be of little assistance in mitigating impacts on facilities which are not included in the new community, such as hospitals, inter-town transportation, recreational facilities, county government services and facilities, and possibly schools.

The DEIS also ignores the problem of jurisdictional mismatches, which occur when the communities experiencing rapid growth lack access to the tax base provided by energy development.

Perhaps the most serious failing of the DEIS, with regard to the socio-economic impacts of shale development, is its mis-statement of the ability of local governments to finance new public facilities from increased tax revenues arising from shale projects. The DEIS cites tax and employment benefits resulting from the development of NOSR (5-50):

> Total public tax revenues generated by the project would amount to over $10 million annually. Public costs would include $6 million in local government expenditures and $4.5 million for expanded human services. Consequently, the cost of the 50,000 BPD NOSR development could feasibly be offset by revenues generated by pub' c activity.

This statement completely ignores the "front-end financing" problem. The State of Colorado's Department of Local Affairs' Division of Impact Assistance has developed a scenario model for analyzing the implications of proposed energy and mineral dvelopments. Preliminary data from this study shows that local communities can expect a 20 year deficit in a cumulative fiscal balance resulting from credited revenues and debited costs (Department of Local Affairs, "Socio-economic Impact Assessment Methods", 1980, 33). Since the data were based on a private development on public land, this is a "best case" scenario. If the NOSR project is government owned and company operated, payments-in-lieu-of-taxes will never make up the cumulative revenues/costs balance and local communities can expect to confront a fiscal deficit for the life of the project. 3-15

Money for impact mitigation is needed prior to energy development and during the initial stages of the projects. If this money is unavailable at this time, local goverments must find supplemental sources of funding to meet the demands for the services which they provide. Contrary to assertions in the DEIS, development of NOSR under the lease option will not produce enough revenue to offset the public service costs associated with the first 10-20 years of the project (5-52).

State and local government agencies are very concerned about the fiscal balance problem. Front-end financing alternatives for provision of housing, transportation, water and sewer services, and other human services are needed as impact mitigation strategies to offset socioeconomic impacts which occur immediately in the project development, long before enough tax revenues are generated.

The existing situation is reflected in the Garfield County Commissioners letter to oil shale companies which states that no permits will be issued in Garfield County for oil shale development until there are firm plans for financing front-end costs of public facilities (appended).

3-16 Environmental Impacts. Water is one of the resources whose availability will determine the level of oil shale production. The water consumption projection for NOSR I are substantially lower than figures used in OTA's (1980) study. According to OTA, directly-heated above ground retorts consume 4,900-7,800 AF/yr, including municipal needs and consumption for power generation (OTA, 1980, 367). Indirectly-heated retorts (like TOSCO II) consume 9,400-12,300 AF/yr. The NOSR "reference technology" has seven directly-heated retorts and three indirectly-heated retorts. Assuming they all have roughly the same capacity, the water requirements for the plant should range from 6,250 to 9,150 AF/yr. These figures are 35% to 98% higher than the NOSR DEIS' low estimate of 4,624 AF/yr. Due to water's "limiting factor" position, this discrepancy in water consumption estimation may be significant.

3-17 The DEIS contains no data on the impacts of NOSR development on wildlife or vegetation. Much of the Piceance Basin is critical winter range for elk and deer. The NOSR tract is intensively used for hunting. Any substantial alteration of existing ecosystems could signficantly affect endemic vegetation and wildlife. Both the Colorado Division of Wildlife and Natural Areas Program have identified key animal and plant species in the Piceance Basin as well as their critical habitats. Existing data for the Piceance Basin wildlife and vegetation are extensive, well documented, and easily accessed.

3-18 Long-term reclamation of oil shale disposal sites has not been successfully demonstrated at the scale of commercial operations. The DEIS is very sketchy about how reclamation would be accomplished. Questions of spoil pile stability, leaching, and the uncertainty of revegetation are not raised in the EIS. Statements like "stream diversions may be necessary to mitigate the effects of leachates coming from the spent shale pile" (5-6,7) are not adequate for analyzing the environmental impacts from oil shale development. A 50,000 bbl/d oil shale facility would be the largest mining operation in the history of the state of Colorado and reclamation problems would presumably be of similar magnitude.

COAL LIQUEFACTION

3-19 Technology Selected to Represent Coal Liquefaction. The DEIS used a direct liquefaction process to represent coal liquefaction in its alternative fuels comparison. Indirect coal liquefaction is a more representative coal liquefaction process than the SRC II direct liquefaction process based on the selection criteria in the DEIS (3-1).

As our appended comments demonstrate ("Review of the Coal Liquefaction Alternative in the DEIS...", 10-19), indirect coal liquefaction technologies are more likely to be commercially available at the same time NOSR is expected to reach commercial production. The final products and the markets for the products from the oil shale plant are comparable to those from an indirect coal liquefaction plant but not to those from a direct coal liquefaction plant. Also, although no discussion of markets for end product was included in the DEIS, the markets of the NOSR production facility would most likely be located in the western United States. Direct liquefaction plants will operate initially on bituminous coals located in the Eastern United States. Indirect liquefaction plants are best suited for subbituminous and lignite coals in the Western United States. A true comparison of processes would show that indirect coal liquefaction plants supply the same markets as those which would use liquid fuels from NOSR.

3-20 Range of Impacts. The methodology used in the DEIS of selecting a single coal liquefaction process to represent an industry and a technology is misleading. Environmental impacts of the technologies cited as single values rather than a range of values can result in erroneous conclusions. The wide variety of technologies used to produce liquid fuels, especially from coal and oil shale, suggest that ranges of actual impacts may be much broader than those considered in the DEIS (see Table 4, p.11, "Review of Coal Liquefaction Alternative..." comments).

3-21 Population and Socio-economic Impacts. The DEIS estimates that about 10 times more employees are required than the operation force estimated in a commercial SRC-II plant design analysis prepared for DOE. Table 8 in the appended "Review of the Coal Liquefaction Alternative..."(21) compares plant employment estimates for several coal liquefaction processes. Apparently an error has been made in the DEIS analysis. The size of the error necessitates a re-examination of the socioeconomic impacts attributed to coal liquefaction production.

3-22 It should also be noted that apparently coal mining was not included in the coal liquefaction alternative. The environmental and socioeconomic impacts resulting from coal mining were omitted. Transportation of the coal from the mine to the plant was not included in the analysis. This obviously skews the analysis of socioeconomic and environmental impacts.

Socioeconomic impacts resulting from coal liquefaction technologies will be less in areas that have an existing infrastructure for dealing with coal mining and refining. Some of these areas may occur in the Western United States although siting of highly centralized, concentrated industrial developments in low population density locations will obviously have greater impacts than siting of these facilities in areas of chronic unemployment, high population densities, and larger communities.

3-23 **Environmental Impacts.** The DEIS has contradictory statements on water requirements for a 50,000 BPD liquid fuel facility. Water requirements are stated to be very small with the implication that they are less than the 4,600-17,500 AF/Yr. for NOSR (1-6). Information in the appended "Review of Coal Liquefaction Alternative..." comments (24) shows that the water consumption for a 50,000 BPD liquid fuel facility would be approximately 12,000 AF/Yr. and the water consumption for a 50,000 BPD total fuel equivalent facility would be approximately 8800 AF/yr. Water use estimates in the DEIS of 11,200 AF/yr. for coal liquefaction (5-33) are correct based on our analysis.

3-24 Solid waste estimates for coal liquefaction in the DEIS are also contradictory. The DEIS estimate of 11,344 TPD in a plant with a coal feed rate of 24,300 TPD implies that 46% of the coal entering the plan is ash or refuse. Solid waste production for coal liquefaction is indicated to be 4.5 million TPY (1-7). This number does not correspond with other data in the DEIS (C-20). It is not clear how this much solid waste is generated. Other data sources for SRC-II facilities state that 1.3 million tons of ash would be produced per year. An indirect liquefaction plant producing 50,000 BPD of liquid fuels and approximately 100,000 BPD of total energy and operating on subbituminous coal would produce about 1.3 million tons per year of coal ash ("Review of Coal Liquefaction Alternative...,"25). A source of the discrepancy in solid waste production figures may be that waste material from coal mining operations is included in the coal refuse estimate. Coal mining should be included in the environmental impacts of coal liquefaction. Different solid waste estimates due to using western coal instead of eastern coal should also be included in the coal liquefaction discussion.

BIOMASS/ALCOHOL

3-25 **Technology.** The DEIS states that ethanol from grain was chosen to represent energy sources from biological processes because the technology is considered to be state-of-the-art and currently demonstrates better economies than other biomass technologies (3-10). Although commercial production from woody or lignocellulosic materials (such as wood from commercial forests) and various types of herbage (grasses) has not been demonstrated, the 1980 OTA report, *Energy from Biological Processes*, states that the overwhelming portion of biological energy production will come from these sources. Ethanol production from grain will have a relatively small role in the total composition of energy production from biological sources (OTA, 1980, Vol 1,5).

Thus, the technology described in the Raphael Katzen study and analyzed in the EIS may not be the most representative for the biomass industry.

> The feedstocks with the largest potential for ethanol production-both in terms of the absolute quantity of ethanol and in terms of the quantity of ethanol per acre of cultivated land-are the cellulosis, or cellulose containing, feedstocks. These include wood, crop residues, and grasses, as well as the paper fraction of municipal solid wastes. (OTA, 1980, Vol. II,67).

One might question the size of the biomass plant analyzed in the DEIS as well as the feedstock. The analysis in the DEIS is based on a massive, 50,000 BPD equivalent facility located in central Illinios. In reality, it is much more likely that facilities would be in the 10,000 BPD equivalent range -- or even smaller, on-farm units.

On-farm use of ethanol fuel is an important market for biomass energy production. The Colorado Department of Agriculture's Gasahol Section knows of 20 operating and planned alcohol plants in Colorado. At least half of these plants (and the only two currently operating) are targeted for on-farm production (Colorado Gasohol Promotion Committee, 1980, 7). Farm production of ethanol can take advantage of a variety of feedstocks and boiler fuels. The on-farm production and market capacities are important components of the biomass/alcohol alternative as they hold the most promise for achievement in the short-term. Dispersion of the ethanol production industry will dilute the levels of socioeconomic impacts as well as provide more appropriate marketing structures. An analysis of these factors should be an important component of the discussion on biomass fuels in the DEIS.

3-26 Emissions. Figure 3-4 in the DEIS (3-13) which shows SO_2 emissions for biomass as 16,800 TPY may be in error by a factor of 10. The correct SO_2 figure for biomass would seem to be 1700 TPY. Table 5-10 (5-38) and C-23 display similar computational errors in emissions for alcohol production. It appears that the emission figures are those for uncontrolled emissions; application of emission controls of 90% for SO_2 would lower these values by a factor of 10.

3-27 Population and Socioeconomic Impacts. The population figures discussed in the DEIS appear overestimated (5-57). The OTA report quotes population increases due to a one billion gal/yr. ethanol industry ranging from 920-3100 operations personnel (OTA, 1980, Vol I, 109). A development projected to be one quarter of the OTA scenario shows an operational force of 2,200 people (5-56).

3-28 Environmental Impacts. Figure 3-5 (3-17) in the DEIS shows the water requirements for a biomass 50,000 PBD facility to be 110,000 AF/yr. No discussion accompanies the graph to describe whether the water is consumed and how much is return flow. The DEIS indicates that 15.4 million GPD would require treatment before discharge (5-39). What is the status of the 94 million GPD not requiring treatment (109 total GPD water requirement (C-22))? The Colorado Department of Agriculture has indicated that a 20 million GPY alcohol plant using irrigated corn as a feedstock would need 75,000 to 150,000 AF/yr of water to raise the corn in Colorado. (Gasahol Promotion Committee, 1980, 23). Is some of the water requirement in the DEIS used for irrigated agriculture?

The most important factor in determining a water balance is the amount of water consumed. The DEIS used water delivered in its water requirement analysis. There is little discussion of net consumption of water. There is no assessment of how much of the water is reusable. Methods for treating the wastewater are not discussed.

ENERGY CONSERVATION

3-29 Technology. The energy conservation "alternative" to NOSR oil shale development targets light-duty, gasoline-powered vehicles. The conservation alternative analysis should be based on the amount of the product which can be saved through conservation programs for fuel types that could be substituted directly for the oil shale product.

The end product of the energy conservation alternative -- gasoline -- is not compatible for comparative purposes with the anticipated end products from oil shale -- mid-distillates which include diesel fuel and jet fuel. This incompatibilty is best reflected in the cycle efficiency and net energy balance calculations. Obvious differences in energy requirements exist if different levels of product refining, etc., are required. The DEIS does not discuss these potential differences.

3-30 Environmental Impacts. The analysis of the impacts of the average conservation alternative is confusing and difficult to interpret. It is unclear how figures 3-3, 3-4, and 3-5 should be interpreted. The bar graphs in Fig. 3-5 show that there are no land or water requirements nor solid waste production for the conservation alternative. The energy conservation analysis is limited to air quality considerations. Air pollution emissions (fig. 3-4) are negative for all pollutants analyzed. Based on this emissions analysis, there is much to be said for the conservation alternative. However, the DEIS does not analyze the water requirements, land use, and solid waste production comparisons for energy conservation. We anticipate, should such an analysis be completed, that the values for these factors would be negative; i.e., a saving of water and land, and no solid waste production. We do not know why this analysis was omitted. It should be included in subsequent analyses.

Socioeconomic Impacts. The DEIS states that:

> The conservation alternative is difficult to assess in socioeconomic terms. The primary consequence of saving 50,000 BPD of gasoline is a 0.6% decrease in the amount of gasoline pumped across the nation. This does not sound like enough to affect the service station industry, but might conceivably impact the gasoline distribution industry slightly (5-58). 3-31

The amount of gasoline pumped nationwide hardly constitutes an adequate analysis of the socioeconomic impacts of the energy conservation alternative. For example, a socioeconomic analysis which is in keeping with examining the impacts from using lighter weight automobiles might include projected metal resource requirements, mineral resource conservation potential, recycling, industry retooling, use of existing industry labor force, import quotas, balance of payments, and other factors.

3-32 Table 5-13 (5-59), which summarizes comparative socioeconomic analysis between the energy alternatives, omits energy conservation. We believe that an adequate analysis of socioeconomc impacts for the energy conservation alternative would include the following factors: water and sewer services, hospitals, roads, schools, housing, parks, police and fire protection, and other social services. We anticipate that such an analysis will show that impacts from energy conservation will be negative; i.e., these services will not be required in the target areas.

3-33 The lack of a comprehensive socio-economic analysis for the energy conservation alternative limits the conclusions which can be drawn from it. The DEIS should contain a full-cycle socio-economic and environmental impact analysis for the energy conservation alternative. If the constraints on a more comprehensive analysis of energy conservation are insurmountable, they should be identified as such in the DEIS.

3-34 Other Comments. Notwithstanding the sketchy analysis of the conservation option, it seems clear from the information presented in the DEIS that the conservation option has fewer adverse environmental and socioeconomic impacts than any other alternative, except perhaps for "no action." The "no action" alternative has the disadvantage, of course, that it would seem to involve less production of liquid fuels. Should one draw the conclusion, then, that energy conservation is superior to shale oil production, coal liquefaction, biomass/alcohol, enhanced oil recovery, offshore oil, and tar sand as a way of reducing the nation's imports of liquid fuels? If not, why not?

CONCLUSION

I hope these comments will be helpful to you as you consider revisions or the preparation of a new draft EIS. My staff will be pleased to meet with you and your contractor to discuss the present draft, and we would also be happy to discuss our comments with you over the phone if this would be helpful.

Cordially,

Monte Pascoe
Executive Director

Enclosures

October 30, 1980

Frank Barrows
Exxon Company U.S.A.
Colony Shale Oil Project
Houston, Texas 77001

Dear Mr. Barrows:

On behalf of the Board of County Commissioners, I would like to invite you to a meeting with the Commissioners and representatives of Tosco, Union Oil and Chevron. This meeting will be on Tuesday, November 18, 1980 at 1:30 P.M. at the Garfield County Planning Office.

The Board has taken the position that no further permits for oil shale development will be issued until they have some assurances of how to answer the needs of schools, housing, fire protection, hospitals, etc. Therefore, these issues will be the main topic of discussion.

I urge that you attend as the Commissioners are requesting that only executive level individuals be invited.

If you have any further questions concerning this matter, please feel free to contact me.

Sincerely,

Ray Baldwin

Ray Baldwin
Planning Director

c.c. John Hopkins, Union Oil
Glen Vawter, Tosco
Roger Loper, Chevron
Frank Barrows, Exxon

RESPONSE SET 3

3-1 The technologies for each alternative were chosen based upon the criteria stated on pages 3-1 and 3-2. Indirect liquefaction produces a slate of products less comparable to oil shale than does direct liquefaction. Biomass alcohol from crop residues is an unproven technology. The use of the Colony project to represent the alternative of oil shale development on other lands is a reasonable representative for examining environmental impacts.

3-2 The comparisons between alternatives is as complete as possible. Each alternative considered all operations which were conducted within the boundaries of the project that normally contribute to the production of the standard product for that alternative. Any differences which occur are not believed to materially affect the comparisons within the range of uncertainty for the numbers used.

3-3 Added information on endangered/threatened plant and animal species has been included in this final EIS. The level of detail provided in the ecosystem impacts section for NOSR has been increased. It is believed that a summary of the major ecosystem impacts resulting from NOSR 1 development represents an appropriate level of detail for the purpose of this document.

The EIS does address the front-end financing issue in a generic manner, due to the fact that more detailed and reliable information is simply not available at this time. Nonetheless, we believe that a general statement of the issue is sufficent to address the point at the level of a programmatic discussion. Other more detailed studies are going on at the present time, for example, the efforts of the Colorado Cumulative Impact Task Force.

If the NOSR Development alternative is proposed in the future by DOE, the results of the Cumulative Impact Task Force efforts would be integral to any development plan which is formulated and would be reflected in future NEPA documents. Any such plan would also be integral to the public regulatory environment which may evolve in the region as a direct result of the Task Force's work.

3-4 The comment, with respect to citing data sources and biomass, is correct and these problems have been corrected in the Final EIS. Other figures concerning shale and capital costs are correct as printed.

3-5 "Meaningful development" is, admittedly, an ambiguous term, but allows such diverse factors as the economy, international tensions and domestic oil production to be considered. It is by no means the only, or even the major factor, affecting the decision on NOSR 1. Refer to responses 2-7 and 2-8.

3-6 Admittedly, the linearity assumption made in the EIS is a simplifying one; however, it is one for which no real methodological option existed at the time the study was performed. In order to gather more insight into the nature of the relationship between increased production and degree of impact, much more detailed information on each alternative would be required. Such information was limited at the time of the study and is still limited. Detailed site-specific exploration of each alternative was not within the scope of the programmatic EIS. Furthermore, in order to investigate a potential non-linear relationship between production and impacts, many additional assumptions would have to be made about the future impacted environment. Grounds for making such assumptions are weak and potential study results more uncertain. For these reasons the linear assumption was employed in the study methodology, although the potential non-linearity is recognized as a legitimate concern. In response to this comment the text has been clarified where appropriate to indicate potential non-linear synergisms or economies.

3-7 The alternatives are compatible. Refer to the response for comment 3-2. Mining and transport of coal were considered for liquefaction, but the descriptive text did not make that clear. This was remedied. The shale alternatives do consider upgrading, but not refining and transportation of the product.

Shale oil will replace imported crude on a one-for-one basis and will not involve the expenditure of additional energy for refining and transportation.

3-8 Cycle efficiency included all operations that are performed within the project boundaries plus conversion and thermal losses. A complete net energy analysis, including secondary indirect energy usage was performed in February and March, 1981. It is included as Appendix C. As can be seen, the final figure for the net energy analysis, which includes indirect energy, is essentially the same as the cycle efficiency, which considered only primary energy. This suggests that the "major energy input stages of the process" are the primary energy inputs. Net energy analyses are time consuming and expensive, and for the purposes of the comparisons performed in this EIS, cycle efficiency was considered adequate. However, net energy efficiency for each alternative is now included.

3-9 Refer to the response to Comment 2-2.

3-10 The differences in emissions between the NOSR reference case and Colony are due to the differences between the processes being used. The sources cited are adequate to support the figures listed. OTA estimates are based upon generalities and engineering assumptions for the oil shale industry as a whole. NOSR and Colony estimates are based upon information supplied by the developers of those specific processes and are believed to be more accurate. However, since both sets are estimates, it would be improper to label one "correct" and the other "incorrect." Refer to pages 3-1 and 3-2 for selection criteria. Colony meets these criteria satisfactorily.

Emissions for the Colony project have been revised, based on more current information. Emissions data from the conditional PSD permit issued to Colony in July, 1979 have been incorporated in the text and comparative tables.

3-11 At the time the decision was made to use point specific values, it was felt this would not severely prejudice any comparison. In retrospect, an uncertainty range might have conveyed a more accurate picture. Nonetheless, by adhering to the selection criteria on pages 3-1 and 3-2, a workable and satisfactory comparison has been presented.

3-12 The capital cost for the Colony plant was calculated from a September 1977 estimate of $1.05 billion using the 1978 inflation rate. Other estimates, including OTAs, have the benefit of information not available when this EIS was produced. However, the most recent capital cost estimates available are incorporated in this final EIS. Chase Manhattan Bank, at a Navy energy seminar in February 1981, stated that capital availability will not be a problem for the oil shale industry.

Capital costs for the commercial-scale SRC II plant were taken from the reference cited and are believed to be accurate. Support for this conclusion is obtained from the "Final EIS, SRC II Demonstration Project" January 1981, which states:

> "The assessed [tax] value of the demonstration plant is expected to be about $467 million (assuming a market value of about $1.4 billion) . . ."

The demonstration plant referred to is the 6,000 ton per day facility at Morgantown, WVA. All capital cost and operating cost figures will have the dollar year noted in this final EIS.

Capital cost for the biomass plant of $58 million are in 1978 dollars, as was noted on page B-24. By applying the inflation rate escalation, one would arrive at the $64 million figure in 1980 dollars. These two numbers are substantially the same.

3-13 There are no reliable or authoritative engineering based estimates of the manpower requirements associated with the construction and operation of a 50,000 bpd oil shale facility. "Actual experience" with the Union and Colony projects does not extend beyond the first year of project construction and there are no firm estimates or forecasts of manpower requirements for these two precedent developments. The estimates cited in the draft EIS are based on the Environmental Impact Statement for the Colony Oil Shale Project in western Colorado. The OTA figures may also underestimate or overestimate the work force requirements that could ultimately prevail under a NOSR 1 development option. Differences in mining and processing methods, timing and on-site and off-site logistics, and ancillary facility requirements, as well as specific work force requirements for community development and socioeconomic impact mitigation measures that may accompany a NOSR development option will all measurably influence the total employment and population effects.

The "peaking problem" referenced in this comment is one which could be alleviated by the NOSR project under the proper circumstances. The sequential peaking of construction workforces employed by "first generation" projects in the southeastern Piceance Basin would result in infrastructure capacity designed to accommodate a peak construction workforce and its accompanying population. Under current projections of first generation facilities, the last oil shale project is scheduled to reach this peak construction level around 1990. Without an adequate economic base to generate additional employment and accompanying population increases, the infrastructure capacity designed to accommodate a population associated with the departing labor force would be excessive to serve the needs of the remaining population. With creative structuring of NOSR development to time construction activities to peak over an extended period, this phenomenon could be significantly alleviated or eliminated.

3-14 The Colorado Cumulative Impact Task Force is currently in the process of analyzing the public infrastructure needs accompanying large-scale economic growth in the NOSR region. It is expected that one result of this effort will be the development of a computerized cost/revenue model which could be used to project probable fiscal results of any of a number of impact mitigation measures, including the development of a new town or the expansion of existing communities, as well as a host of other possibilities - e.g., consolidation of school districts, annexation, changes in tax rates and structures, creation of regional impact districts, etc.

One significant benefit of the model would be its capability to forecast the effects of specific scenarios of NOSR development, if that option is selected. For example, if construction of shale facilities on NOSR lands were timed to begin at the completion of other facilities in the region, it would appear that the detrimental effect of outmigration of large numbers of construction workers could be diminished or at least delayed until the region had had an opportunity to broaden and diversify its economic base.

On the point of jurisdictional mismatches, it is relevant to this discussion that the Task Force Work Group 4 has taken the position that public revenues must be projected for each taxing entity in the region. This effort would provide the quantitative support for any decisions made to evaluate mechanisms to mitigate the fiscal imbalances occuring in areas outside a specific facility's zone of tax exposure. Again, if the NOSR Development option is chosen, the project would have the benefit of the Task Force's comprehensive analysis to guide NOSR mitigation efforts.

As to the specific point that "the new town for the Colony project is likely to house only 50% of the workforce for that project," it is significant to note that Battlement Mesa (Colony's new town) has been planned as an open community with a projected build-out capacity designed to provide infrastructure to accommodate dwelling units for twice the total population directly employed by the Colony project as well as Colony's induced population. Therefore, if the comment's assumption is valid that only 50% of Colony's workforce will actually be housed at Battlement Mesa, the town will be only 25% filled by Colony-related population, with the remaining 75% available to accommodate other projects in the region - including NOSR-based populations.

3-15 The "front-end financing problem" is recognized in the text. However, a detailed quantitative analysis of the type suggested by this comment is premature and beyond the scope of this general discussion of programmatic alternatives.

3-16 This comment does not consider the differences in processes nor in the sizes of feedstock and spent shales. It is not valid to assume all indirectly fired retorts are identical. The discussion of the NOSR plant explicitly describes the operation of the two different indirect retorts. The data provided for the NOSR case were supplied by the processes' developers and are believed correct.

3-17 The description of the affected environment section for NOSR 1 has been revised to include information from recent onsite surveys.

3-18 The discussion of solid waste impacts (page 5-8) has been modified to address these comments.

3-19 This comment appears to have been based upon the analysis presented in the study enclosed as comment Set 10. Please refer to the detailed responses to that set, pages 3-1 and 3-2 for selection criteria and the response to comment 2-10 for shale oil markets.

3-20 Refer to response 3-11.

3-21 The employment estimates for the SRC II plant were taken from the authoritative source cited and were believed to be correct at the time the draft EIS was written. Subsequent revisions have been made by the SRC II project and the latest figures from their January 1981 EIS were incorporated in the final EIS.

3-22 Mining employment was included as was transportation. Refer to the response to comment 3-7.

3-23 The reference to a "very small" water requirement for coal liquefaction has been replaced by the actual requirement number.

3-24 Solid waste estimates were inconsistent and a single value was used in the final EIS. The latest available information, the January 1981 SRC II Final EIS, lists solid waste as approximately 41% of the coal feed. Eastern coal will be the feedstock.

3-25 Refer to the selection criteria on pages 3-1 and 3-2 and to the response to comment 3-10 for a discussion concerning selection of processes. The 50,000 bpd plant satisfies the selection criteria and, although it is possible that biomass units would be in the 10,000 bpd range (or more likely 3,600 bpd), the comparisons in this programmatic level document would not be markedly affected.

3-26 A computational error was made in calculating biomass emissions and has been corrected. In addition, assumed control efficiency for SO_2 has been changed from 90% to 95% in response to another comment. Revised emissions estimates appear in the text of the EIS. See response 16-4.

3-27 The EIS plant is 50,512 bpd which is closer to three quarters than one quarter of the OTA figure, which is one billion gal/yr or 72,150 bpd. The population estimate in the EIS of 2219 workers is 71.5% of the OTA upper bound and would appear reasonable.

3-28 The water usage figures originally presented were in error and have been revised.

3-29 Gasoline will be one of the products from shale oil. The amount of gasoline produced from a barrel of shale oil will be determined by market demand. Conservation of gasoline which would have been used in passenger automobiles is directly substitutable for a shale oil product and is therefore a valid comparison. The potential differences in refinery processing will not materially affect the results of the comparisons.

3-30 See response to comment 2-5 regarding water, land and solid waste impacts of the energy conservation alternative.

The text has been modified to clarify the interpretation of Figures 3-3, 3-4 and 3-5.

3-31 Because of the complexity inherent in the analysis of an almost limitless variety of conservation alternatives, the specific discussion of the impacts of this alternative action was purposely curtailed in the EIS.

3-32 See response to comment 2-5.

3-33 See responses to comments 5-1(G) and 2-5.

3-34 Conservation has been represented as having fewer adverse environmental and socioeconomic consequences, and will have a positive effect on air quality. Conservation will displace imported oil, and is an important means of reducing imports. However, conservation alone is not expected to be adequate by itself to meet import reduction goals. This EIS presents environmental and socioeconomic comparisons as a part of a larger decision-making process, where programmatic conclusions are reached based on a larger body of data.

Department of Local Affairs
Colorado Division of Planning
Philip H. Schmuck, Director

1876
Richard D. Lamm, Governor

State Clearinghouse
State Cartographer
State Demographer
Land Use Commission
208 Water Quality

M E M O R A N D U M

DATE: December 12, 1980

TO: Steve Ellis
Colorado Clearinghouse

FROM: Philip H. Schmuck
Division of Planning
Phil

SUBJECT: Review of DOE's Draft Programmatic EIS for the Naval Oil Shale Reserves (NOSR) in Garfield County - #80-106

The Colorado Division of Planning has reviewed the above referenced Draft Environmental Impact Statement, and is concerned that the findings of this EIS do not appear to relate to upcoming DOE decisions.

One of the decisions to be made is whether to promote development of oil shale on federal land (p.1-1). The comparison of eight liquid fuel alternatives would supposedly serve as input to this decision. However, the EIS states on page 1-4 that although "such comparisons are useful, they do not lead directly to any conclusions". The EIS goes on to say that many energy sources may need to be developed concurrently, and therefore that the eight options evaluated in the EIS are "not true alternatives".

CEQ Regulations for implementing NEPA state in section 1502.1 that "Agencies shall focus on significant....alternatives and shall reduce.... the accumulation of extraneous background data". We would suggest that unless the options of energy conservation, biomass/alcohol, etc., are treated as alternatives to oil shale development, that they not be discussed as such in this EIS and that other alternatives be included to satisfy the requirements of NEPA. (The Division of Planning has already forwarded to DOE its suggestions for what those "other alternatives" should be. See the February 1980 letter prepared at the pre-scoping stage.) 4-1

The second decision to be made by DOE (p.1-1) is whether to develop the 35,000 acre NOSR #1 in northwest Colorado. This decision was of particular interest to the State, and many issues were brought up at the pre-scoping stage that agencies wanted addressed. The EIS recognized that such concerns are important; page 1-5 refers to one when it says that an analysis of NOSR development "should ultimately be considered in a regional energy development context". "However", the EIS continues, "such an analysis of NOSR 1 development is not included in this EIS and is instead planned for a site specific EIS".

520 State Centennial Building, 1313 Sherman Street, Denver, Colorado 80203 (303) 839-2351

4-2 Are we to accept that State concerns won't be addressed until a site specific EIS is prepared? If so, how do we react to the statement made on page 1-4 that "the decision whether to develop NOSR 1, and by what means, will be made by the Secretary of Energy based on the findings of THIS EIS....?" (emphasis added). If this is true, then where does a site specific EIS fit into the federal governments' decision-making process?

In conclusion, the Division of Planning feels that the draft EIS submitted for our review is inadequate both because it does not appear to meet NEPA requirements, and because it does not address State concerns. We are available to clarify any of the above comments upon request.

KO/ann

RESPONSE SET 4

4-1 Refer to the response to comment 2-7.

4-2 Refer to the response to comment 2-6.

STATE OF COLORADO

OFFICE OF ENERGY CONSERVATION
Office of the Governor
1525 Sherman Street
Denver, Colorado 80203
Phone (303) 839-2507

Richard D. Lamm,
Governor
Joseph H. Zettel
Acting Executive Director

DATE: December 10, 1980

TO: Monte Pascoe, Executive Director
Department of Natural Resources

FROM: Joe Zettel, Acting Executive Director

SUBJECT: Draft Programmatic Environmental Impact Statement - Development Policy Options, Naval Oil Shale Reserves, Garfield County, Colorado

The Colorado Office of Energy Conservation is pleased to submit the following comments to the Department of Natural Resources which is acting as the lead agency for review of the Naval Oil Shale Reserves (NOSR) Draft Programmatic Environmental Impact Statement (DPEIS). As oil shale resources are developed in Colorado, it is imperative that the processes used be energy efficient to maximize recovery and minimize energy usage, the communities developed and resulting infrastructure be energy conservative, and the public and private investments made be beneficial to the citizens of the state and the nation.

With these considerations in mind, our comments are divided into those of a general, overall nature and comments of a more specific nature.

GENERAL COMMENTS

Our general comments focus on three major issue areas: (1) the conservation alternative analysis, (2) the net energy analysis methodology, and (3) the secondary impacts of community growth and development on energy requirements. Each of these three issues are discussed individually below:

5-1((1) Conservation Alternative Analysis. This office is very pleased to see the "conservation" option considered as an alternative to oil shale development. However, a couple of questions arise relating to the degree of importance attributed to this option. The analysis used for this option concerns itself only with light duty gasoline powered vehicles.

This might be a reasonable assumption if all the oil shale will be refined into gasoline. This undoubtedly is not the case. The conservation alternative analysis should be based on the amount of product which can be saved through conservation programs for fuel types that could be substituted directly for the oil shale product. The other major question is why is the conservation option not clearly the preferred alternative based upon the analysis in the NOSR DPEIS? Why does the document not lead to a decision or a preferred alternative?

5-2(G) (2) Net Energy Analysis Methodology. Without being able to ask the preparers of the DPEIS technical questions relating to the assumptions used in determining the net energy analysis, it is difficult to comment in a very meaningful manner on this topic. It is apparent, however, that the scope and parameters of the analysis are inadequate and need to be comprehensive. A net energy analysis must be inclusive of the energy required from extraction to end use of the shale oil product at the very minimal. This will drastically reduce the inflated "process only" figures given in the document. Reference is made later in our specific comments as to a more appropriate and accurate source to use when determining project energy efficiency rates. Also addressed later in more detail are questions relating to a demonstration need for this development and to the end use products of oil shale.

5-3(G) (3) Secondary Impacts of Community Growth and Development on Energy Requirements. To be comprehensive, a net energy analysis should also include the energy requirements of expanded or new communities directly attributable to oil shale development. Although these impacts will probably not be spelled out in detail until the site-specific EIS, this must be considered initially at the programmatic level of decision making. The U.S. Department of Energy should include conditions for any oil shale development project which require energy efficient community design, layout, orientation, and thermal standards for buildings and the use of renewable resources as much as economically feasible based on life-cycle costing techniques.

We would have appreciated input form the preparers of the document prior to the submission of these comments. A continuing dialogue would be immensely helpful in answering these initial questions and concerns, and future ones as well.

SPECIFIC COMMENTS

Review of the NOSR DPEIS has raised several key issues and concerns which are addressed more specifically as follows:

A. What are the assumptions and methodologies used in the net energy analysis of the oil shale development and the seven alternatives?

1) Is only the processing stage of oil shale production included?

2) Why haven't the extraction, crushing, refining, and the distribution to the end user been included in the analysis?

5-1(S) It appears that only fuels in and out are compared and indirect or invested energy is ignored in the analysis of net energy. The DPEIS should not claim to have any definitive energy efficiency information as it stands. A comparative assessment among alternate energy sources should be based upon a true net energy analysis and not a simplistic input/output model. A net energy analysis should account for the complete direct and indirect activities which must be utilized to produce energy from a given resource. The study should include all steps (exploration, extraction, conversion, transportation to end users, etc.) in bringing the fuel from reserves in the ground to the point of end use. Fossil fuels can be directed through a number of extraction and processing methods to the end users. OEC encourages the study of net energy analysis to determine which of these methods can produce and deliver the energy in the most efficient manner.

This office strongly recommends that the preparers of this document follow the more comprehensive net energy analysis methodology used in the Colorado Energy Research Institute's report entitled "Net Energy Analysis: An Energy Balance Study of Fossil Fuel Resources" (Golden, CO; April, 1976). The process outlined in Figure 5(D), p.II-11, should serve as the basis for a more comprehensive analysis. While some of the data in the CERI report can be revised, the process methodology is the important aspect to follow. Updating this study's process and methodology has been proposed by the Colorado School of Mines Research Institute and the NOSR DPEIS preparers should follow through on this. However, the methodology in the CERI report does not include any of the secondary energy impacts associated with community growth and development resulting from the oil shale project. These should at least be recognized, if not incorporated into a revised net energy analysis model to make sure that all the true energy costs directly associated with resource development projects are included.

5-2(S) B. The DEIS gives a cycle efficiency of 79% for Tosco II/room-and-pillar mining process (p.C-7). The data source cited for the figure is a 1975 University of Oklahoma study: Energy Alternatives-A Comparative Analysis. In our analysis of the Oklahoma study we find an efficiency rating for Tosco II of 66.7% (p.2-35). Why is there a discrepancy?

5-3(S) C. What is the projected end use of the oil shale from NOSR?

1) If the end product is gasoline, then why has reduction in vehicle weight been the only scenario considered in the conservation alternative? A better, more detailed approach would be to analyze the total potential savings in transportation from increased mass transit, carpooling, vanpooling, mpg fleet averages, and other transportation/energy related policies. A helpful resource would be Policy Alternatives to Reduce Transportation Energy Consumption by the Colorado Energy Research Institute, Golden, CO., July, 1979.

2) If the end product is not gasoline, then why is energy conservation in the transportation sector (specifically light duty vehicles) considered as an alternative to developing the oil shale?

3) If the end product is primarily mid-distillates, the conservation alternative analysis should have addressed the appropriate conservation measures for this fuel type's end users.

5-4(S) D. Energy conservation is described as advantageous in reducing air pollution. Conservation impacts on water requirements, land use, water quality, and socio-economic factors are not analyzed. What are the constraints on a more comprehensive analysis of the energy conservation alternative?

5-5(S) E. What is the purpose of the NOSR DPEIS?

1) If the purpose of the DPEIS is to determine whether the government should finance commercial development of oil shale on federal land (specifically the NOSR), how will this DPEIS, and the consideration of the alternatives, aid in decision making?

2) What action is the DPEIS recommending?

3) Alternatives are compared in the analysis, in the tables and graphs in section 3, p.3-12 to 3-26; why weren't the conclusions drawn as to the preferred alternative?

4) Based on the analysis, why isn't the alternative of energy conservation the preferred alternative?

We appreciate the opportunity to comment on this document. If you should have any questions or we can be of further assistance, please do not hesitate to contact me or David L. Ford of my staff.

cc: Colorado Clearinghouse
pl

RESPONSE SET 5

(G) - General Comment (S) - Specific Comment

5-1(G) Several transportation fuels may be refined from oil shale, including gasoline, diesel and jet fuel. The definition of the conservation alternative employed in the EIS based on reduced automobile weight and gasoline consumption was chosen to represent conservation options in the transportation sector. This definition was selected because it allowed quantitative measures of change (reduced vehicle weight and fuel consumption) and impact (reduction in air emissions) to be calculated in a relatively straightforward manner. No assumptions were made about changes in human behavior, such as driving less or switching to mass transit. Although other definitions of the conservation alternative are possible, the results of the EIS comparative analysis would not have changed significantly. The environmental benefits of the conservation alternative relative to the other technology alternatives compared in the EIS are obvious. However, the definition of the conservation alternative and impact analysis were designed to serve the purpose of the EIS, that is, a relative comparison of alternatives, and not as a comprehensive study of energy conservation in the transportation sector.

Land, water and solid waste benefits of conservation were not calculated. However, implicit in the discussion in the draft EIS was the fact that no negative impacts on these areas are expected from the conservation alternative. Although this does not constitute a quantification of the environmental benefits of conservation on land, water and solid waste, it does provide an indication of the relative merits, from an environmental standpoint, of conservation and other technology alternatives. This point was made explicit in the final EIS.

The conservation alternative is the "environmentally preferable" alternative and the final EIS was revised to reflect this. However, although it is the environmentally preferable alternative, it is not DOE's preferred alternative, for the reasons discussed in the response to comment 2-7.

5-2(G) See response to comment 5-1(S).

5-3(G) See response to comment 5-1(S).

5-1(S) The net energy analysis performed in February and March of 1981 and included as Appendix C contradicts the contention that the parameters of the analysis are inadequate and the figures inflated. The model used for the cycle efficiency calculation gave essentially the same results as the net energy analysis which was more comprehensive than the methodology used in the cited CERI report. Refer to the response to comment 3-8 for more discussion.

5-2(S) See response to comment 2-2.

5-3(S) See response to comment 5-1 (G).

5-4(S) See response to comment 2-5.

5-5(S) Refer to the responses to comments 2-6 and 2-7.

COLORADO STATE DEPARTMENT OF HIGHWAYS

November 24, 1980

NOV 25 1980
DIV. OF PLANNING

Mr. Philip H. Schmuck
Director
Colorado Division of Planning
520 State Centennial Building
1313 Sherman Street
Denver, Colorado 80203

Dear Mr. Schmuck:

The Colorado Department of Highways has completed its review of the Draft Environmental Impact Statement for the Naval Oil Shale Reserves and has the following comments.

6-1 The document does not address the secondary transportation impacts caused by population increases as requested in our comments on the Pre-EIS Scoping material. These impacts need to be evaluated in the Final EIS, and sufficient mitigation should be provided.

Thank you for the opportunity to review this document.

Very truly yours,

Harvey R. Atchison
Director
Division of Transportation Planning

By
Barbara L.S. Chocol
Manager
Impact Evaluation Branch

REG/rg

4201 EAST ARKANSAS AVENUE DENVER, CO 80222 (303) 757-9525

RESPONSE SET 6

6-1 Secondary transportation impacts caused by population increases, along with mitigation measures, were not identified in the Draft Programmatic EIS because they are primarily site-specific considerations. It was not possible to address these secondary impacts for each alternative case and was not appropriate to examine them in detail for NOSR development at this time. Both primary and secondary transportation impacts would be addressed in detail in any site- and project-specific EIS, and specific mitigation measures would be proposed.

COLORADO
HISTORICAL
SOCIETY

The Colorado Heritage Center 1300 Broadway Denver, Colorado 80203

November 19, 1980

NOV 21 1980
DIV. OF PLANNING

Mr. Stephen O Ellis
Principal Planner
A-95 Clearinghouse
420 State Centennial Building
1313 Sherman Street
Denver, Colorado 80203

Dear Mr. Ellis:

This office has received and reviewed the draft programmatic environmental impact statement "Development Policy Options Naval Oil Shale Reserves, Garfield County, Colorado".

7-1 We anticipate the consideration of cultural resources in the future site-specific EIS for NOSR 1. It is our understanding that a cultural resource survey was conducted on the Naval Oil Shale Reserve in 1973. This office would appreciate receiving a copy of the report as it would aid in our review of this proposed project.

If this office can be of further assistance, please contact the Compliance Division at 839-3392.

Sincerely,

Arthur C. Townsend

Arthur C. Townsend
State Historic Preservation Officer

ACT/WJG:ss

RESPONSE SET 7

7-1 A cultural resources inventory of NOSRs 1 and 3 was completed in 1981. The environmental impact on cultural resources is one of the factors required to be considered in any site-specific EIS.

An inventory was indeed performed in 1973 by A. E. Kane, Department of Anthropology, University of Colorado, Boulder. DOE has a copy of that report with photographs, which is available through:

Department of Energy
Naval Petroleum and Oil Shale Reserves (EP-20)
Forrestal Building, Room 3E094
1000 Independence Avenue SW
Washington, D. C. 20585
Attn: Donald Silawsky

STATE OF COLORADO
Richard D. Lamm, Governor
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WILDLIFE
Jack R. Grieb, Director
6060 Broadway
Denver, Colorado 80216 (825-1192)

DEC 2 1980
DIV. OF PLANNING

November 28, 1980

TO : Stephen O. Ellis
Colorado Clearinghouse

FROM: Al Whitaker
Wildlife Program Specialist

SUBJ: Naval Oil Shale Reserves - Draft EIS
EIS #80-106

This agency has reviewed the above-referenced EIS. Needless to say any development of oil shale will have an impact on the State's wildlife resources. Therefore, we would support an alternative other than development of the Naval Oil Shale Reserve.

We are particularly concerned that Federal policies and goals may change with regard to liquid fuels. If the Naval Oil Shale Reserves are developed along with private tracts, the cumulative impacts could be substantial. In fact, development of NOSR could be the "straw that breaks the camel's back" for the area's wildlife resources. In the final EIS, we would like to see a comparison of the environmental impacts of development of NOSR along with several levels of private and other public oil shale development. 8-1

/d
cc: P. Olson

DEPARTMENT OF NATURAL RESOURCES, Monte Pascoe, Executive Director • WILDLIFE COMMISSION, Wilbur Redden, Chairman
Donald Fernandez, Vice Chairman • James Smith, Secretary • Jean K. Tool, Member • Vernon C. Williams, Member
Michael Higbee, Member • Sam Caudill, Member • Richard Divelbiss, Member

RESPONSE SET 8

8-1 The request to perform cumulative impact analysis for all environmental factors likely to be affected has been made in a number of areas. Such an analysis, to include wildlife resources, would be presented in a site-specific EIS. Also refer to the response to comment 2-8.

COLORADO DEPARTMENT OF HEALTH

Richard D. Lamm
Governor

Frank A. Traylor, M.D.
Executive Director

MEMORANDUM

TO: David W. Kuntz, Assistant Project Director
Energy Policy and Planning
Colorado Dept. of Natural Resources

FROM: Paul Ferraro, Special Assistant for Energy Policy
Health Protection & Environmental Programs
Colorado Department of Health

RE: Comments on Draft Environmental Impact Statement - U.S. Department of Energy, Naval Oil Shale Reserves DEIS #80-106

DATE: December 10, 1980

We have reviewed the subject draft EIS and have the following general comments. Due to the type and scope of the document, the Department of Health is not providing detailed comments at this time but will do so, if and when a more complete environmental technical analysis including monitoring and modeling is provided.

General Comments

1. The overall approach developed in this EIS is of interest and the Department of Energy should be commented for taking a broader approach for this project. However, we question that the analysis provides the answers needed to decide whether or not to develop the Naval Oil Shale Reserves. Based on the report, one would conclude that the best alternative would be conservation versus developing the Naval Reserve at either the 50,000 or 200,000 barrel per day levels. We believe that the approach used in this DEIS would be of significant value if done at a national level considering the total energy needs in the future and considering all sources of energy available. This type of overall national analysis would provide the basis for directing Federal research and development funds, granting of leases, providing impact assistance planning and funding

[illegible]
DEC 10 1980

4210 EAST 11TH AVENUE DENVER, COLORADO 80220 PHONE (303) 320-8333

to minimize environmental, socio-economic and labor impacts. If such a study is done, the Department of Health would like to participate in the development stages.

9-1 2. Before a decision can be reached on whether or not to develop the Naval Oil Shale Reserves, the EIS should contain a section that assesses the status and impacts of the oil shale activities already underway or planned for in Colorado, Utah and Wyoming.

3. Finally, we believe that the State of Colorado should have a significant role in the decision-making process and should be a member of any work group established to advise DOE on whether or not to develop this project.

I appreciate the opportunity to participate with you and other State agency respresentatives at the November 20, 1980 meeting with DOE to discuss this project.

Paul Ferraro

Paul Ferraro, Special Asst. for Energy Policy
Health Protection & Environmental Programs

PF:ja

cc: Bob Arnott
Rich Halvey
Stephen Ellis

RESPONSE SET 9

9-1 As was noted in Section 2 of this final EIS, the status and impacts of other oil shale projects are not necessarily directly relevant to the need for development of NOSR 1, given the reserve's unique national security status. The cumulative impacts of NOSR 1 and other nearby projects have been addressed in this document, and will be examined in greater detail in a site-specific EIS before any decision is made to develop NOSR 1.

[illegible] Labor [illegible] the Department of Health would like to participate [illegible] development process.

[illegible] whether or not [illegible]

[illegible] should have [illegible] and should [illegible] DOE [illegible]

[illegible] between you and other State agency representatives [illegible] meeting with DOE to discuss this project.

[illegible]
Health Protection & Environmental Programs

PA:ja

cc: Bob [illegible]
[illegible]
[illegible]

DRAFT

Review of the Coal Liquefaction Alternative In the Draft Programmatic Environmental Impact Statement Development Policy Options Naval Oil Shale Reserves Garfield County, Colorado

DRAFT

Colorado Energy Research Institute

December 2, 1980

Prepared by

Energy and Resource Consultants, Inc.

Boulder, Colorado

Abstract

The draft programmatic environmental impact statement contains both methodological and technical flaws. The flaws can be corrected, and doing so would provide a more accurate and informative assessment of the environmental consequences of developing the Naval Oil Shale Reserve, coal liquefaction plants or other liquid fuel production alternatives.

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I. Summary

One of the alternatives to developing the Naval Oil Shale Reserve property in Colorado is to manufacture liquid fuels from coal. This report is a review of the description and analysis of the coal liquefaction alternative contained in the Draft Programmatic Environmental Impact Statement, Development Policy Options, Naval Oil Shale Reserves, Garfield County, Colorado. The draft environmental impact statement (DEIS) was made available for review in September, 1980, by the U.S. Department of Energy. This review is not intended to be a standalone document. It is presumed that the reader is familiar with the DEIS.

Several aspects of the DEIS could be changed in order to characterize more accurately the coal liquefaction alternative to developing the Naval Oil Shale Reserves. This report describes the methodological, as well as technological, improvements which could be made in the DEIS.

In general, the document could be improved in the following ways:

- 10-1 The DEIS did not compare similar fuels. The DEIS looked at "liquid fuels" without regard to the substitutability of the products from the different processes. A more representative comparison of the environmental aspects of the alternatives would be achieved by examining liquid fuels of comparable quality. The coal liquefaction analysis was based on a process which produces primarily fuel oil but also naphtha and LPG; the conservation alternative displaced gasoline; and the shale oil alternative only produced crude oil rather than a refined product.
- 10-2 The analysis did not compare all of the operations that are required to produce products of comparable quality. The extraction of feedstock, processing, and upgrading all need to be included for a valid comparison to be made. The shale oil option included the shale mining, but the coal liquefaction option did not appear to include the coal mining. The upgrading did not exist for the shale oil but did exist to some extent for the coal liquefaction option and definitely existed for the conservation option which displaced a very high quality product, gasoline.
- 10-3 The concept of characterizing emissions by selecting a "typical process" which has emissions that are "neither excessively large nor small" does not convey

enough information to understand properly the potential impacts of the different alternatives. Supplying a range of air emissions, water effluents, solid waste quantities and other impacts, along with one set of impacts which may be considered typical would convey much more information about the range of outcomes which could occur for each of the liquid fuel alternatives.

10-4 o The technology which was selected to represent coal liquefaction was direct liquefaction. A different technology, indirect coal liquefaction, should have been used. The technology selection criteria presented in the DEIS support the selection of indirect coal liquefaction. Indirect coal liquefaction technologies are more likely to be commercially available at the same time that commercialization of the Naval Oil Shale Reserves would be contemplated. The final products and the markets for the products from the oil shale plant are more comparable to those from an indirect coal liquefaction plant than to those from a direct coal liquefaction plant.

10-5 o The sizing of the facilities to fifty thousand barrels per day and two hundred thousand barrels per day did not seem to include the multi-product production that occurs at synthetic fuels plants, particularly those for coal liquefaction. The multiproduct slates, which include substantial quantitites of gases as well as liquid fuels varying from fuel oil to gasoline, should be considered.

10-6 o The impacts of coal liquefaction plant employment appear to be based on an incorrect estimate of the number of employees. The DEIS estimate appears to be 10 times too large for the direct liquefaction alternative selected.

10-7 o The DEIS estimate of solid waste production at the coal liquefaction plant is inconsistent with the coal feed rate and implies that about one-half of the coal feed to the plant is either ash or refuse.

Each of these topics will be described in more detail in the next section.

10-8 The quality of the DEIS would be tremendously improved if more documentation of the calculations and assumptions that were made in developing the parameters for each of the liquid fuels alternatives was included in the document. Because a variety of different documents were frequently used for each technology it is impossible to determine precisely the validity of many of the numbers from the information included in the DEIS. Data from different documents, produced in different years, and based upon different states of knowledge, were all included in the coal liquefaction analysis. It is not clear why some old documents were used instead of more current documents. An explanation of why this was done and back-up calculations would be very beneficial.

The rest of this report describes in more detail the suggested improvements listed above, with a focus on the coal liquefaction alternative. The next section discusses the improvements which were listed above. The last section, Section III, contains comments on individual pages of the DEIS.

II. Potential Improvements in the Draft Environmental Impact Statement

The coal liquefaction alternative presented in the Draft Environmental Impact Statement (DEIS) can be more accurately characterized by making several changes in the DEIS. Some of the changes are methodological and pertain to the entire DEIS and some of the changes pertain specifically to the coal liquefaction alternative. This section describes both types of changes.

1. Compare comparable products.

The DEIS, although it did consider liquid fuels in general, neglected to include the variations in quality among the different alternatives. The differences are summarized for some of the alternatives in Table 1. The Naval Oil Shale Reserve process would produce crude oil needing substantial upgrading at a refinery in order to produce consumable products. The shale oil crude which would be produced may be of such low quality that specially designed refineries would need to be used in order to upgrade it.

At the other extreme, the DEIS included the conservation of gasoline as an alternative to processing the shale oil at the Naval Oil Shale Reserve. This alternative would "produce" a very high quality liquid fuel, gasoline. By reducing the amount of gasoline consumed through conservation measures, substantially more liquid fuel would be conserved by avoiding energy inputs of the various upgrading processes which crude oil must go through than was characterized by the DEIS.

A wide variety of products can be produced during coal liquefaction. The different possible products are listed in Table 2. The coal liquefaction process which was selected in the DEIS (which is not considered to be the correct one, as described later) produces primarily fuel oil, a substantial quantity of high quality petrochemical feedstocks, some naphtha (which can be upgraded to gasoline at modest expense) and significant quantities of pipeline quality gas which is substitutable for natural gas. These products are all of higher quality than the crude oil considered for the oil shale options.

By not comparing equivalent alternatives the conclusions that would be reached using the draft document could be substantially different than those which would be reached if the same types of products in the same general amounts were assumed to be produced in each alternative. The variations in fuel mixes which occur with individual processes cannot be precisely matched due to the different feedstocks and technological

Table 1

Liquid Fuels and Products of Selected Alternatives in the DEIS

	Crude Oil	Fuel Oil	Premium Feedstock	Gasoline
o NOSR	X			
o Other Oil Shale	X			
o EOR	X			
o OCS	X			
o Conservation				X
o Alcohol/Biomass				X (ethanol)
o Coal Liquefaction		X	X	

Table 2

Possible Coal Liquefaction Products

- Fuel Oil
- Naphtha (Premium Gasoline Feedstock)
- LPG (Premium Chemical Feedstock)
- Gasoline
- Methanol
- SNG

But Never a "Syncrude"

constraints imposed by the processes used with the different alternatives, but more accurate comparisons can be made by selecting the markets and products for which the NOSR plant would be designed. A more representative comparison of the alternatives can be made by including upgrading of the lower quality products to the quality required by the end users. Alternatively, the analysis of the energy conservation option could be improved by assessing the impacts of the mix of measures which would save the fuel slate produced by oil shale plants rather than focusing only on gasoline.

2. Include all of the liquid fuel production operations for each of the alternatives.

For most of the alternatives three general processing steps are needed to make liquid fuels. These are feedstock extraction, feedstock processing, and raw product upgrading to final products. Table 3 summarizes which process steps were included in the quantitative environmental and socioeconomic analysis of the alternatives. In general, assessments of the liquid fuels options did not include all the processes which would actually be required in order to manufacture liquid fuels of comparable quality. Including all of the necessary processing steps and their impacts would give a more valid comparison among the alternatives.

Extraction of shale oil by mining was included for the Naval Oil Shale Reserve option but coal mining was not included for the coal liquefaction option. Consequently the impacts on the environment and the socioeconomic impacts due to the larger labor force from the coal mining operations were omitted. The transportation of the coal from the mining operation to the plant was also not included. The case could be made that the mine producing the coal was already in operation and that the coal liquefaction plant was simply a new market for the existing coal production. It is not stated that this is the assumption nor is it stated why the assumption, if it was made, would be valid. The general plan of increasing coal production in the United States would tend to require that new coal mines would be opened to supply the incremental demand imposed by a major coal liquefaction plant. The omission of the impacts due to transporting the coal from the coal mine to the plant also would either need to be included in the final EIS, or else an explanation of why they do not need to be included in the overall impact of a coal liquefaction plant should be described in the final EIS.

Table 3

Process Steps Included for Environmental and Socioeconomic Analysis

	Feedstock Acquisition	Feedstock Processing	Final Product Manufacture	Product Use
o NOSR	X	X		
o Other Oil Shale	X	X		
o EOR	X			
o OCS	X			
o Alcohol/Biomass		X	X	
o Conservation				X
o Coal Liquefaction		X	X (Partly)	

Processing of the feedstock was included for both the Naval Oil Shale Reserve and the coal liquefaction options. It was not included for some of the other options such as outer continental shelf oil drilling. Again, the impacts from the production of the products that consumers would use rather than the production of raw feedstocks is necessary in order to give a balanced analysis. Alternatively, the energy conservation option could include the benefits of the avoided processing steps which would have been required to transform crude oil into finished products.

The upgrading of the crude shale oil product was not included in the DEIS. The crude shale oil may either be processed on-site or off-site. The assumption made in the DEIS apparently was that it would be processed off-site. This assumption does not remove the impacts that would occur due to manufacturing finished consumer products at a remote facility. In some cases these facilities that would upgrade the crude shale oil would be in the same general vicinity as the shale oil plants. For example, Gary Energy Corporation's Fruita refinery is being examined as a candidate for expansion in order to accomodate crude shale oil. The analysis is currently examining the economic feasibility of processing ten thousand barrels per day of various oil shale feedstocks into both commercial transportation grade fuels and military jet fuels.

The most recent conceptual design[1] for the coal liquefaction option selected, SRC-II, does include the production of finished products for about 85% of the products. Fifty-four percent of the products are in the form of fuel oil which is probably not acceptable for diesel fuel or jet turbine fuel but which would be acceptable as a burner fuel in applications such as boilers. Fifteen percent of the SRC-II product, however, is in the form of a raw naphtha which is not a suitable motor vehicle fuel. With upgrading the naphtha makes a very high quality gasoline. By not including the upgrading of the naphtha, a raw product with little commercial value except as a burner fuel is being produced contrary to what a commercial operation would actually do. The environmental consequences of the upgrading of the naphtha would be little different than those which occur in petroleum refineries and it seems reasonable that petroleum refinery naphtha processing would be a valid basis for assessing the environmental consequences of upgrading the naphtha produced from the SRC-II process.

Among the documents describing the SRC-II process and its environmental consequences and the upgrading steps that would be necessary for producing gasoline from the naphtha are the multi-volume SRC-II Demonstration Project Phase Zero Deliverables. These reports were presented to the U.S. Department of Energy on July 31, 1979 by the Pittsburg & Midway Coal Mining Company. The bulk of the information in these documents is publicly available and could be used to improve the quality of the DEIS.

3. Use a range of environmental consequences.

The approach selected for the DEIS was to select a single process (e.g. SRC-II) to represent a technology (e.g. coal liquefaction). Using single values instead of ranges to represent the environmental consequences of the technologies considered in the DEIS can be very misleading. In some cases, such as in the presentation on the health effects of the different alternatives, ranges of consequences were included in the document but usually only single values were used. The wide variety of technologies which could be employed to produce liquid fuels, particularly from coal and oil shale, suggests that the range of actual impacts can be much wider than those included in the DEIS. Table 4 lists estimated emissions for several pollutants for four coal liquefaction processes.

Table 4 illustrates that no single process can be considered "typical" for all pollutants. The table also indicates the ranges of emissions which are expected based on the designs now hypothesized for various processes.

The DEIS should accurately characterize the impacts that could be expected. A more accurate characterization in the final EIS would include some processes which would produce either substantially more or substantially less of certain environmental impacts. By including the ranges of the impacts from the different liquid fuel alternatives, as well as typical values, decision makers will have the opportunity to better assess the environmental consequences of promoting the development of the Naval Oil Shale Reserve.

4. Use indirect coal liquefaction as the representative coal liquefaction process.

The DEIS uses the SRC-II process to represent coal liquefacation. Indirect coal liquefaction should be used instead of SRC-II.

Table 4

Stack Emission Rates for

50,000 BBL/Day Coal Liquefaction Plant

Process	Emissions (All Stacks-G/S)		
	Particulates	SO_2	NO_x
Mobil-M* (Coal-Methanol-Gasoline)	7.9	76	132
Fischer-Tropsch* (Coal-Gasoline-Fuel Oil)	51	103	201
Exxon Donor Solvent* (Coal-Fuel Oil)	4	179	56
SRC-II** (Coal-Fuel Oil)	3.1	35	110

Sources: *Synthetic Fuels and the Environment: An Environmental and Regulatory Analysis, U.S. Department of Energy, June 1980, pp. H-4 to H-5.

**Draft Programmatic NOSR EIS, p. C-20, based upon the Draft EIS for the SRC-II demonstration project.

Indirect coal liquefaction is a more representative coal liquefaction process than the SRC-II process using the selection criteria listed on page 3-1 of the DEIS:

- Feasible commercial production by 1990;
- Available environmental cost and engineering data usable at fifty thousand BPD production;
- Process demonstrated on a commercial scale;
- Environmental emissions neither excessively large nor small compared with other technologies that could represent the alternatives,

As well as a selection criterion not included in the DEIS:

- Market considerations for the oil shale products.

The SRC-II process is one of several processes which produce liquids using "direct liquefaction" technology. The major difference between direct liquefaction and indirect liquefacation is that:

- during direct liquefaction coal is mixed with a solvent and directly made into liquids,
- during indirect liquefaction coal is first gasified, and the gases are then catalytically transformed into liquids.

Table 5 summarizes how well indirect and direct coal liquefaction match the selection criteria. Feasible commercial production by 1990 for the SRC-II process is uncertain for both the 50,000 BPD size and the 200,000 BPD size which are used in the DEIS. The SRC-II process is currently being considered for a demonstration plant at Morgantown, West Virginia which, when completed, would produce about 15,000 BPD of liquid products. The plant will not be constructed and operating until the mid-1980's. The first commercial plant will be an extended version of the demonstration plant and is not expected to begin operation until the very late 1980's, at which time it would produce approximately 84,000 BPD of liquid products.

Large scale manufacture of SRC-II or other direct liquefaction products is not reasonably expected to reach the scale approaching 200,000 BPD total production until well after 1990 due to the uncertainty surrounding the design and operation of the equipment in the plants. There is also a three year lead time on critical process equipment which further extends into the future the time for the large scale producton of direct liquefaction products. Therefore, SRC-II does not seem to meet the first criterion of feasible commercial production by 1990, except for a pioneer commercial plant which would not be truly typical of the currently conceptualized commerical facilities.

Table 5

Indirect and Direct Coal Liquefaction Matched Against the Process Selection Criteria

Criteria	Indirect Liquefaction	Direct Liquefaction
1. Commercial by 1990?	Commercial now in several variations	Pilot scale now Demo scale, mid to Late 1980's Commercial post 1990
2. A. Environmental data available?	A. Yes, but not compiled in detail in one document. Coal gasification, methanol, refinery process data exists Mobil study has detailed data. F-T catalyst plant uncertain.	A. Yes, compiled with SRC-II phase zero Deliverables. Best of any processes' data
B. Cost data available?	B. Yes, Mobil study is best	B. Yes, SRC-II Phase zero best
C. Engineering data available?	C. Yes, Mobil study is best	C. Yes, SRC-II Phase zero best
3. Process Demonstrated?	Yes, large commercial scale	No, pilot scale only at present
4. Typical Impacts	Vary	Vary
5. Markets like NOSR?	Yes, products interchangeable	Not for diesels, jet turbines

Indirect coal liquefaction is a commercially available technology today and over 100,000 BPD of production sized equipment is currently operating in South Africa. The equipment which is used is commercially feasible and the design information necessary for commercializing indirect coal liquefaction in the United States is available. The production of fuel oil, diesel fuel, jet turbine fuel, gasoline and methanol via indirect coal liquefaction are all commercially (although possibly not economically) possible today in the United States.

Environmental cost and engineering data suitable for a 50,000 BPD production plant of a quality suitable for the DEIS analysis do exist for the SRC-II process, but also exist for indirect liquefactation processes. The data used in the DEIS for the SRC-II process are from several sources. The best data for the SRC-II process are those contained in the phase zero deliverables that the Pittsburg & Midway Coal Mining Company prepared under its contract with DOE. These data are probably the best publically available environmental production, design, and cost data for any coal liquefaction process.

Indirect coal liquefaction seems to have been precluded from further consideration in the DEIS because it was felt that environmental cost and engineering data were not available for the different processes.[2] No statement is made as to which specific data were lacking, but because indirect coal liquefaction processes are combinations of well known and well defined modules which are commercially available it seems inappropriate to not include indirect coal liquefaction due to lack of data. The first module in an indirect coal liquefaction plant is the production of coal gas. Many commercially available coal gasification processes are available with well defined engineering costs and environmental data. Frequently the Lurgi coal gasification process is preferred for the available indirect liquefaction designs. Lurgi coal gasification environmental data, in particular, are available from the extensive environmental analyses which have been conducted for the SNG plants which are proposed in various parts of the United States.

The second step in the production of coal liquids using the indirect process is shifting the composition of the coal gas to one which is appropriate for making the products desired. The modification of gas compositions such as would be used in indirect coal liquefaction processes is a very common operation in the manufacture of a variety of industrial chemicals as well as in petroleum refining. This step is also required for making SNG from coal. The gas composition shifting process is fully enclosed and it is unlikely that it would be an emitter of pollutants. The variety of existing industrial processes using this step, plus its use in SNG plant designs, suggests that enough data exist to characterize gas shifting.

The final step in the production of coal liquids using an indirect process is the manufacture of the liquids from the gas by catalytically restructuring the molecules in the gas. This is again an enclosed process and it is unlikely that it would be a source of emissions. Furthermore, the restructuring is an exothermic process so that no energy is consumed in the process, but rather is released. Thus, no additional energy would need to be supplied from an outside combuster such as a boiler or process heater. The cooling water requirements for this type of operation have been well documented in a variety of sources.

One example of an integrated process which is almost identical to the indirect liquefaction process is the commercial production of methanol from natural gas. The only difference is that the gas for indirect coal liquefaction is manufactured from coal and the gas for commercial methanol plants is manufactured from natural gas during the first step of the process. Therefore, combining the data from the first parts of an SNG plant (to get the gas) with data from the last parts of a methanol plant (to make the gase into methanol) would characterize an indirect liquefaction plant.

The DEIS excluded a recently developed indirect coal liquefaction process which was developed by Mobil that produces gasoline from methanol. The reason given for its exclusion was that the environmental impacts for the integrated unit are unkown. This statement is misleading considering that the scale-up for the SRC-II process from the 50 ton per day SRC pilot plant to a commercial facility is a larger leap than the commercial production of methanol using existing methanol technology connected to commercial coal gasification technology with the final step of catalytically restructuring the methanol into gasoline using the Mobil process. The Mobil methanol to gasoline reactor is a fully enclosed process. It would be reasonable to expect few air emissions from the process of converting methanol to gasoline using the Mobil process.

Besides the availability of information for the individual subprocesses involved in indirect liquefaction, a detailed engineering analysis was conducted for indirect coal liquefaction processes including that which is used in South Africa as well as the Mobil-M process and the manufacture of methanol from coal. This data is publicly available and was developed for DOE by Mobil Research and Development Corporation.[3] This analysis includes the amounts of coal which are required, the production slates which are produced, the emissions from the plant including off-sites such as boilers, as well as the water requirements for the processes. Detailed flow diagrams and material balances are included in this document. Cost estimates are produced for each of the indirect liquefaction alternatives explored. Estimates are made of the number of operations workers which would be employed at the plant. Furthermore, the estimated number of workers required to construct the facility are also included in the analysis for both a 40 hour work week and for a 40 hour work week with a 14 hour overtime premium.

One possible weakness of the Mobil analysis of indirect coal liquefaction technologies is that the particulate emissions from the catalyst plant of the SASOL type technology is not included. Another DOE document entitled, Synthetic Fuels and the Environment: An Environmental and Regulatory Impacts Analysis, which was published in June, 1980, has detailed emissions characteristics for several indirect as well as a direct liquefaction technologies. Included in the SASOL plant characterization is an estimate of the particulate emissons from the catalyst plant.

The third process selection criterion stated in the DEIS was that the process should have been demonstrated at an acceptable scale. As previously mentioned, the SRC-II process has been operated at a size which has a coal feed rate of 50 tons per day. The 50 TPD plant needs to be scaled up many more times to reach a commercial size than the technology which is currently operating at a commercial scale which would be used in an indirect coal liquefaction plant be it SASOL type, methanol type, or Mobil-M gasoline type.

The last criterion stated in the DEIS for technology selection was that environmental emissions be neither excessively large or small compared with other technologies that could represent a particular alternative. The direct liquefaction plants such as SRC-II have very different emissons characteristics than indirect liquefaction plants. If the indirect liquefaction plant were to be selected as the prototypical coal liquefaction process, it may be that SRC-II would be excessively large or small. Environmental consequences of indirect liquefaction as opposed to direct liquefaction of coal are quite different. Direct coal liquefaction produces compounds which have very different molecular structures than the type of hydrocarbons that are produced at indirect liquefaction plants. In general, the highly aromatic liquids produced by direct liquefaction processes are more active than the paraffinic liquids produced at SASOL type plants and the methanol produced at methanol plants. The aromatic liquids of direct liquefaction plants also are more carcinogenic than the liquids produced by indirect liquefaction and consequently the health and safety consequences of the two processes could be very different.

The last process selection criterion which is important is the markets which the Naval Oil Shale Reserve Oil Shale Plant would serve. This criterion was not included in the DEIS. The markets that the Naval Oil Shale Reserve production facility would most likely serve would be located in the west. The direct liquefaction plants will operate initially on bituminous coals located in the eastern part of the United States. Indirect liquefaction plants are most suited for coals of the type located in the western United States. Therefore, the coal liquefaction process which is most likely to be able to supply the markets which would need to have liquid fuels from the Naval Oil Shale Reserve are indirect liquefaction processes.

Another consideration when determining which coal liquefaction process should be used is the types of fuels produced from oil shale compared to the types of fuels produced from indirect liquefaction and direct liquefaction of coal. The ability of fuels from the processes to substitute for one another is summarized in Table 6. The general type of product produced from oil shale will be a paraffinic slate of fuels. Indirect liquefaction also produces a paraffinic fuel slate but direct liquefaction produces aromatic fuels. In general the aromatic fuels produced from a direct liquefaction process such as SRC-II will be fuel oil for combusters such as boilers, and high quality gasoline. The fuel oils produced from the direct liquefaction processes are generally not suited for either diesel fuel or jet turbine fuels such as those required for aircraft. The fuel oils produced from both indirect liquefaction plants as well as oil shale facilities are suited for both diesel fuel as well as jet turbine fuel. Therefore the types of products produced from indirect liquefaction are a closer match to the types of products which are produced from oil shale when the need for liquid fuels is matched to the fuel characteristics.

Based on the five technology selection criteria described above, the most representative coal liquefaction technology to be included in the EIS is indirect coal liquefaction rather than direct coal liquefaction. It is still recommended that a range of emissions or environmental consequences be used as well as the typical one. The range could be produced using only indirect liquefaction technologies by selecting appropriate processes within the indirect liquefaction category which have a variety of environmental consequences.

Table 6

Indirect and Direct Coal Liquefaction Product-Market Matches Compared to Oil Shale Liquids

Product	Indirect	Direct
Gasoline	As good as oil shale product	Probably better than oil shale
Diesel Fuel	As well suited as oil shale	Poor compared to oil shale
Jet (turbine) Fuel	As well suited as oil shale	Probably very marginal compared to oil shale
Lt. Fuel Oil	As good as oil shale product	As good as oil shale
Hvy. Fuel Oil	As good as oil shale product	As good as oil shale
Market Region	Western States	Eastern States

For example, SASOL type indirect liquefaction would have much higher particulate emissions than methanol production because of the particulates emitted from the catalyst production plant.

5. **Use consistently sized facilities and account for the multi-product slates of the different processes.**

The different technologies considered in the DEIS do not all produce the same products. Besides the differences in final liquid fuel characteristics there are also substantial amounts of by-products produced by some of the technologies. In particular, both direct coal liquefaction and indirect coal liquefaction processes produce substantial quantities of by-products. Typical product yields are given in Table 7. Indirect coal liquefaction produces typically 50% of its energy products in the form of gases and direct liquefaction would be expected to produce about 30% of its products in the form of gases, including both synthetic natural gas and LPG. Proper comparison of the environmental consequences of the different liquid fuel production options should make equivalent product slates for all energy forms, not just the liquid fuel forms.

One way in which the equivalent comparisons could be made for the liquid fuel production options which do not produce the gaseous fuels and other fuel products would be to examine the consequences of additional fuel production facilities which would be dedicated to making the fuel forms which are absent from the liquid fuel plants. For example, the oil shale option which would not make as much gaseous fuel as an indirect liquefaction plant could be combined with a coal gasification plant to make the equivalent amount of gaseous fuel. In this case the comparison would be between an oil shale facility combined with a gasification plant and the indirect coal liquefaction plant. Even for the indirect liquefaction plants, substantially fewer employees are estimated to be needed than the estimate given in the DEIS.

6. **Reexamine Coal Liquefaction Plant Employment Estimates and the Resulting Socioeconomic Impacts.**

The DEIS estimates that about 10 times more employees would be needed to operate an SRC-II plant than is given in the detailed estimate of the conceptual commercial SRC-II plant design recently prepared for DOE.[4,5] The plant employment estimates from these two sources for an SRC-II plant, and estimates for two types of indirect liquefaction plants are given in Table 8. The large differences between the estimates indicates that

Table 7

Typical Coal Liquefaction Process Plant Design - Yields

Typical Process Yields (% Fuel Energy)

Products	Methanol Plant	F-T Gasoline Plant**	Mobil Gasoline Plant	Direct Liquefaction#
Liquids				
Gasoline	2	25	41	16
Diesel, #2	—	5	—	54
Resid. Oil	—	1	—	
Alcohols	48	3	—	—
Gases				
SNG	50	64	54	8
LPG	—	2	5	23

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* Tremendous flexibility of yields is possible. These values are from detailed analyses performed by others.
**An extreme case, the usual maximum gasoline:Diesel Fuel Ratio is 75:25, not 83:17.
# For an eastern bituminous coal. Western coals give higher gas yields. Does not total to 100% due to rounding.
Note: Methanol, F-T, and Mobil gasoline processes are all indirect coal liquefaction processes.

Table 8

Plant Employment Estimates for Coal Liquefaction

Source	Number Plant Employees at 50,000 Bbl/Day Plant
DEIS*	4,000 at SRC-II Plant
SRC-II Project Phase Zero**	350 at SRC-II Plant (Scaled from 507 at 73,000 Bbl/day)
Mobil Report*** (Scaled with Phase Zero Factors)	600 at Mobil-M Plant (Total Fuel Basis) 1,400 at Mobil-M Plant (Liquid Fuel, Only, Basis)
Mobil Report# (Scaled with Phase Zero Factors)	870 at F-T Plant (Total Fuel Basis) 2,600 at F-T Plant (Liquid Fuel, Only, Basis)

Notes:

* Draft Programmatic NOSR EIS, p. C-19

** The Pittsburg and Midway Coal Mining Company (P&M), "Conceptual Commercial Plant, Plant Descriptions," Deliverable Number 8, Vol. 2 of 5 (July, 1979) SRC-II Demonstration Project, Phase Zero, Task Number 3.

*** M. Schriener, Research Guidance Studies to Assess Gasoline from Coal by Methanol-to-Gasoline and SASOL-Type Fischer-Tropsch Technologies, (August, 1978), pp. 200-201.

# Schriener, pp. 200-201.

an error has been made. Since the large socioeconomic impacts of coal liquefaction are largely driven by the number of plant employees, these estimates need to be reexamined in the DEIS.

The estimates for total number of employees for the two indirect liquefaction plants listed in Table 8 were based upon the estimated number of plant operators given in reference 6. Total plant employeers, including permanent maintenance and non-craft (administrative) employees, were estimated by assuming the same ratio of total employees to operators for the indirect liquefacation plant as for the direct liquefaction plant. Even for the indirect liquefaction plants, substantially fewer employees are estimated to be needed than the estimate given in the DEIS.

7. Reexamine the Estimated Amount of Solid Waste Generated by Coal Liquefaction.

The DEIS estimates of solid waste are not consistent with the process description as will now be described. The coal feed rate given is 24,300 TPD, the solid waste production estimate for gasifier slag is 2,860 TPD and the estimate for tramp iron and other coal refuse is given as 8,484 TPD.[7] The estimate of the total waste produced is 11,344 TPD. This figure implies that 46% of the coal entering the plant is ash or refuse. This estimate is obviously in error. This estimate may be so high because mine waste may be included in it, although the process description given in the DEIS does not include mining operations. The gasifier slag stream estimate is reasonable and implies a coal ash content of about 10 to 12 percent, which is a typical value for the coals examined for the SRC-II process.

As previously suggested, coal mining should be included in the environmental impacats of coal liquefaction. If the solid waste estimates in the EIS do include mining operations it should be stated. It is also recommended that the different solid waste estimates due to using western coal instead of eastern coal be included in the final EIS.

8. General Comments

The assessment of the coal liquefaction alternative to the development of the Naval Oil Shale Reserve can be improved in other ways. One of the ways in which it could be improved would be to use consistent data sources. For example, the direct coal liquefaction option presented relied upon data sources produced between 1975 and 1980 without

describing why one data source was selected instead of another. This approach seems to be particularly inadequate considering that the phase zero deliverables on the SRC-II process, which became publicly available in July, 1979, include detailed discussion of the SRC-II process design, emissions, and socioeconomic impacts. Another problem associated with the SRC-II discussion in the DEIS is that the differences between the demonstration plant, the first commercial plant, and the conceptual commercial plant were not taken into account in the analysis. For example, the yields presented for the SRC-II process are for the demonstrated and not for the conceptual commercial plant which would be the more appropriate indicator of the product slate for the process.

The mixing of the different references and failure to supply any backup calculations or written documentation makes it difficult to calibrate the accuracy of the analysis.

III. Specific Comments on Individual Pages of the Draft Programmatic EIS

This section contains specific comments addressing particular statements made in the draft programmatic EIS. The comments are sequentially arranged by page number.

10-10 Page 1-6. The water requirements for a 50,000 BPD liquid fuel facility are stated to be very small for coal liquefaction with the implication that they are less than the 4,600-17,500 acre feet per year for the Naval Oil Shale Facility. This statement is inaccurate based upon the phase zero conceptual commercial plant descriptions for the SRC-II process which were delivered to DOE on July 31, 1979. Based upon Volume 2 of Task #3, the estimated water consumption of the conceptual commercial SRC-II plant is 28.19 gallons per million Btus of fuel products. The conceptual commercial plant design is based upon a plant producing the equivalent of 100,000 BPD of fuel products with about 69% of the fuel products being fuel oil and naphtha. Therefore, the range of water consumption for a 50,000 BPD liquid fuel facility would be approximately 12,000 acre feet per year and the water consumption for a 50,000 BPD total fuel equivalent facility would be about 8,800 acre feet per year. Both of these figures are substantially larger than those implied on page 1-6 of the DEIS. The water use estimates on page 5-33 (11,200 AF/yr) of the DEIS are correct.

For indirect coal liquefaction a reasonable estimate of the water consumption for a plant which has not been thoroughly optimized for reduced water use is about 35 gallons per million Btus of fuel products produced. For a plant which produces 50,000 BPD of gasoline the annual water consumption would be approximately 22,000 acre feet per year based on the gasoline production and about 11,000 acre feet per year based upon the total fuels production including the synthetic natural gas and LPG. These numbers are probably somewhat higher than what would occur at a plant which had been optimized for energy use and minimum water consumption but are not so high as to not indicate that the statement on page 1-6 of the DEIS is probably incorrect about the implied amount of water which would be used at a coal liquefaction plant.

Page 1-7. The solid waste production for coal liquefaction is stated to be 4.5 million tons per year. This number does not correspond with the information supplied in Appendix C page 20. It is substantially less than the information in the Appendix. It also is not clear how this much solid waste is generated. According to the phase zero documentation for the conceptual commercial SRC-II plant, which is approximately the size of a 100,000

BPD production facility, only 1.3 million tons of ash would be produced per year. The size of the plant that is used on page 1-7 is not stated, but in either case the amount of waste is significantly greater than the coal ash production.

An indirect liquefaction plant which was set up to produce 50,000 BPD of liquid fuels and approximately 100,000 BPD of total energy operating on subbituminous coal would produce about 1.3 million tons per year of coal ash. This figure is also much smaller than the solid waste estimate on page 1-7 of the DEIS.

Page 1-7. Coal liquefaction is stated to have the greatest health and safety hazard potential. This statement should be reevaluated if indirect coal liquefaction is used as the standard coal liquefaction technology. The aromatic nature of direct coal liquefaction products give this process its high health and safety hazard. Indirect coal liquefaction products are not aromatic in nature and consequently would have a much lower health and safety hazard potential.

10-11 Page 3-9. A statement is made that Morgantown, West Virginia is representative of the areas in which the first liquefaction plants will be built. This statement is correct for direct liquefaction plants but is probably incorrect for all coal liquefaction plants. The indirect liquefaction processes will probably be located in the west. Coal gasification is the first step in indirect coal liquefaction and consequently plants employing indirect liquefaction would be sited near coal feedstocks which are most suitable for gasification. The most suitable coal gasification feedstocks are in the western regions of the country, in particular those regions that have subbituminous and lignite coals, not the bituminous coals such as in the Morgantown region.

Page 3-2. The efficiency for coal liquefaction processes is given as 71%. Seventy-one percent would be typical for direct liquefaction processes but is too high for indirect liquification processes. It is not clear what information is given when the efficiencies of individial processes are compared. Process efficiency is an important criterion in some regards for the economics of a process. It is unclear what the importance of an efficiency comparison is when comparing alternative liquid fuel production schemes, particularly when different product slates and large volumes of by-products are manufactured.

Page 3-20. The potenial health and safety hazards of coal liquefaction are rated between major and moderate in Figure 3-6. This analysis is based upon the SRC-II process. As previously stated, indirect liquefaction plants including both Fischer-Tropsch synthesis facilities, methanol facilities and the Mobil M-Gasoline process would produce much smaller quanities of carcinogenic compounds than the highly aromatic structures produced during direct liquefaction.

The products produced by the SRC-II process are mostly end products and all of the products produced during indirect liquefaction are final products, whereas those produced from the typical oil shale plant included in the DEIS are only crude oil products which need substantial further upgrading. Therefore, the impacts associated with the upgrading should also be considered in any health studies for oil shale but would not need to be included additionally for the indirect liquefaction process and only very moderately for the direct liquefaction process.

Page 3-24. The labor force estimate for peak construction appears to be reasonable for both indirect coal liquefaction as well as direct coal liquefaction.

Page 4-9. A description is given of the environment affected by an SRC-II plant located near Morgantown, West Virginia. The environment of Morgantown, West Virginia is quite different than that for a typical indirect liquefaction plant located in the west. It would be appropriate to expand this section to include the western state areas which would be typical sites for indirect coal liquefaction plants.

10-12 Page 5-32. The discussion on direct liquefaction emissions mentions that methane might be released during coal mining operations and that this would contribute to hydrocarbon concentrations. This statement is somewhat erroneous because methane is a nonreactive hydrocarbon and thus is neither regulated nor contributes to air quality deterioration.

10-7 (cont.) Page 5-34. The discussion on solid waste impacts from direct coal liquefaction appears to be incorrect. Using information in the conceptual commercial plant description of the phase zero deliverables, a 50,042 BPD liquid fuels plant using the SRC-II process and considering only the fuel oil and naphtha production would use approximately 23,000 tons of coal per day. Assuming that the coal has 12% ash, approximately 2,700 tons per day of coal ash would be produced which confirms the estimate in the DEIS for the gasifier slag stream which is where most of the coal ash would end up. However the DEIS also has approximately 8,500 tons per day of tramp iron and coal refuse being produced as well as the gasifier slag. Combining the figure for the gasifier slag of 2,860 tons per day and the figure for the other solid waste streams of 8,484 tons per day and assuming that these nonreactive solids all came from the coal, approximately 11,000 tons per day of nonreactive material come from the coal. With a coal feed rate of 22,000 tons per day these figures suggest that between 30 and 50% of the coal received at the plant is waste. The 30% figure is arrived at by assuming that there will be 11,000 tons per day of waste and that 22,000 tons per day are needed and the 50% figure is arrived at by assuming that the 22,000 tons of coal which are received at the SRC-II plant in the commercial design is constant with the 11,000 tons per day of the draft being an accurate estimate of the waste. In either case, the total quantity of waste from the process seems to be much larger than that which would actually occur.

One source of this discrepancy might be that the waste material from the coal mining operations are being included with the coal refuse estimate. If this assumption is being made it should be clearly stated. If it is not being made, some additional documentation supporting the estimate in the DEIS should be supplied other than referencing a report.

10-13 Page 5-35. The statement is made that because coal liquefaction processes use more severe operating conditions that larger quantities of polycyclic organic molecules would be produced. This statement is based upon poor logic. The production of the polycyclic compounds in direct liquefaction processes depends upon the precursor molecules in the feedstocks and the process type, not the severity of the operation. An excellent counterexample to this logic of severe operating conditions producing polycyclic compounds is that coal gasification (which uses much more severe operating conditions than direct liquefaction) produces very few polycyclic compounds, particularly in the slagging, entrained flow processes.

Even though the logic is incorrect, the conclusion that for direct liquefaction more polycyclic organic molecules will be produced is correct. For indirect liquefaction it is not correct to assume that more polycyclic organic molecules would be produced than the production of liquids from shale oil, petroleum or biomass/alcohol.

10-14 Pages 5-59 and C-19. The capital cost for the direct coal liquefaction plant is given as 2.4 billion dollars for a 50,000 ton per day SRC-II plant. This figure is much higher than those which were given in the July, 1979 conceptual commercial plant descriptions under the phase zero deliverables for the SRC-II demonstration project. This document gave a capital cost of 1.7 billion dollars, including a 20% contingency. The 1.7 billion dollar cost is based upon November, 1978$. It is not known which year dollars have been used in the DEIS. This discrepancy in capital cost is approximately 35% and would need to be based upon different plant design assumptions. Because the product slates used on page C-19 are based on the draft Environmental Impact Statement for the SRC-II demonstration project at Morgantown, it would seem appropriate to base the capital cost of the SRC-II commercial plants on the documents that are being developed by Gulf Oil for a commercial plant based upon the same design data rather than on a different source of information.

The peak construction employment for direct coal liquefaction listed on page 5-59 in general are supported by the estimates given in the phase zero deliverables for the SRC-II project.

10-15 Page 5-65. An irreversible and irretrievable commitment of resources is stated to be coal (which could otherwise be used to produce metallurgical coke) used for liquid fuels feedstocks. This statement is not necessarily correct because direct liquefaction processes do not need high quality coals such as those used for producing metallurgical coke. Indirect liquefaction processes work best with subbituminous and lignite coals which are not now suitable coking coals.

Pages C-18 and C-19. The process description for SRC-II is accurate. As previously discussed, indirect coal liquefaction should also be described.

10-16 Pages C-19 and C-20. As previously discussed, the coal feedstock quantities and the solid waste production quantities do not seem to correspond. This may be due to the mixing of different references with different assumptions underlying the amount of coal and solid waste production. This information should be made consistent or else documentation should be included describing the inconsistency. Based upon the solid waste numbers presented on page C-20 almost as much solid waste is produced as coal is fed into the plant.

References

1. The Pittsburg and Midway Coal Mining Company (P&M), "Conceptual Commercial Plant, Plant Description," SRC-II Demonstration Proejct, Phase zero, Task Number 3, Deliverable Number 8, Vo. 2 of 5 (July 31, 1979), prepared for U.S. Department of Energy under contract DE-AC05-780RO3055. p. 2-8.
2. Draft Programmatic NOSR EIS. p. 3-9.
3. Schreiner, Max, Research Guidance Studies to Assess Gasoline from Coal by Methanol-to-Gasoline and SASOL-Type Fischer-Tropsch Technologies, prepared by Mobil Research and Development Corporation, Prepared by U.S. Department of Energy August 1978. NIJS order number FE-2447-13.
4. Draft Programmatic NOSR EIS, p. C-19.
5. P&M, p. 5-13.
6. Schreiner, pp. 200-201.
7. Draft Programmatic NOSR EIS, pp. C-19, 5-34.

RESPONSE SET 10

10-1 The referenced NOSR plant would produce an upgraded shale oil that would be a low sulfur, premium feedstock directly usable in a refinery. To our knowledge, no one in the petroleum, refining or shale industries subscribes to the idea that "specially designed refineries would need to be used in order to upgrade it [shale oil]." The upgrading processes used at the plant site are those that have been industry standards for many years. Shale oil has been successfully refined in two large-scale experiments in 1975 and 1978 for the Navy. In each case, an existing, commercial refinery was used.

The coal liquefaction option selected (SRC II) is considered far preferable to the indirect liquefaction processes for the purposes of this EIS. The "fuel oil" produced by SRC II is a wide boiling range liquid (350^{o}-900^{o}F), comparable to a shale syncrude, less the naphtha fraction. Table 1 in comment set 10 masks this feature, as does Table 2.

Each direct liquefaction option does have a syncrude mode. (See, for example, the H-Coal Syncrude Production Mode, described in the DOE Fossil Energy Program summary document, among numerous references.) The processing steps involved in the direct liquefaction process do have a step analogous to upgrading of shale oil. We believe the selection of SRC II is entirely reasonable and proper. Comparisons, as they stand in the EIS, are considered valid and would not be materially affected by precisely matching fuel product slates.

10-2 The analysis in comment set 10 apparently was compromised by what DOE believes to be errors in Table 3 in that set. For example, feedstock acquisition and processing are required for every option except conservation.

Upgrading of shale oil on site was included. Refer to the response to comment 2-10 for a discussion of shale oil refining location. The product called "fuel oil" in the SRC II design contains both the jet fuel (300-550^{o}F) and diesel fuel (350-650^{o}F) fractions. The environmental consequences of upgrading naphtha from SRC II are out of scope for this EIS.

The final EIS for the SRC II Demonstration Program is more recent and is considered preferable to the Phase Zero document. Its data were incorporated in the final NOSR programmatic EIS.

10-3 Refer to the response to comment 3-11. The EIS is believed to be a reasonable characterization of impacts.

10-4 DOE does not believe that the information in comment set 10 substantiates the contention that indirect liquefaction is a better choice than direct liquefaction. A discussion of some of the reasons for choosing SRC II is on page 3-7 of the EIS. SRC II satisfies the criteria. It was not considered possible (nor absolutely necessary) to include a requirement for interchangeable products in the selection criteria. Shale oil, using a likely refining methodology suggested by Chevron in their shale oil refining study, would produce 17% gasoline, 20% jet fuel, 54% diesel fuel and 9% residuum. According to another Chevron study, SRC II would produce 22% LPG, 14.5% naphtha, which could be used as reformer feed for gasoline, and 63.4% "fuel oil." This fuel oil contains most of the jet fraction, all of the diesel fraction and some residuum. The remaining portion of the jet fraction falls in the naphtha cut. Indirect liquefaction, such as Fischer-Tropsch, according to the Mobil study cited, yields 6.3% LPG, 10.2% mixed alcohols, 68.6% gasoline, 11.7% "diesel fuel", which is really a naphtha-based jet fuel such as jet B or JP-4, and 3.1% "heavy fuel oil," which is really a diesel fuel. These data would appear to refute the statements made under criterion 5 in Table 5 of this comment set, as do the data in Table 7. Therefore, the basis for subsequent assumptions concerning direct versus indirect liquefaction is unsupported in this area. Refer to the response to comment 2-10 for a discussion of markets for shale oil. The discussion of the characteristics on page 10-17 and Table 6 or comment set 10 is not supported by the state of knowledge of fuels chemistry nor any experiments to date, to the best of our knowledge.

10-5 The criteria for selection of liquid fuels options (page 3-1) is for "50,000 bpd. . . of liquid fuels." Product yields in Table 7 of comment set 10 appear to be incorrect. (See response to 10-4.) Comparisons of the environmental consequences of the different liquid fuel options are considered valid for the purposes of this programmatic EIS as they stand.

10-6 The contention that the EIS overstates the SRC II employment by a factor of 10 is not consistent with data in the SRC II Final EIS. The figure cited on page C-19 in the draft EIS was believed accurate when it was taken from the cited reference. Subsequent recalculations by SRC II have cut that figure in half. The new figure supplied by the SRC II Final EIS is now used.

10-7 The January 1981 Final EIS for SRC II lists solid wastes as approximately 41%. Given the range of uncertainty surrounding commercial designs for SRC II, this figure is reasonably consistent with the previous one in the EIS. However, the latest data are now used.

10-8 Those sources considered most reliable were selected to support the EIS analysis. In a few cases, updated sources available since the draft EIS was prepared have been used in the final EIS. Every effort has been made to describe the methodology used in sufficient detail.

10-9 See response to comments 10-2 and 10-8. No reliable sources were omitted, but in areas of uncertainty, such as for plant output, those sources which had corroboration or support, or which were drawn from actual experience were preferred.

10-10 The statement referring to a "very small" water usage for coal liquefaction has been replaced with the actual usage number.

10-11 As has been stated before (responses 10-1 and 10-4), direct liquefaction was the process chosen for the stated reasons. Energy efficiencies were presented to illustrate how much energy each technology must withdraw from the nation's economy to operate compared with how much usable energy each technology returns to the economy. It a valid and very valuable aid in comparative analyses. There is insufficient information available to support the contention that there are more carcinogens in direct liquefaction end products than there are in end products of indirect liquefaction.

10-12 The discussion of methane release has been revised.

10-13 The statements made in the EIS are amply supported in petrochemical literature. The "precursor molecules" exist in coal and the threshold temperatures for PNA formation are in the range of 750° to 900° F, lower than conditions for liquefaction.

10-14 Refer to the response to comment 3-12.

10-15 This section has been revised.

10-16 Refer to the response to comment 10-7.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
1860 LINCOLN STREET
DENVER, COLORADO 80295

JAN 2 6 1981

Ref: 8W-EE

Borgstrom
Woodbury

Ms. Ruth Clusen
Assistant Secretary for Environment
U.S. Department of Energy
Washington, D.C. 20585

Dear Ms. Clusen:

The Region VIII Office of the Environmental Protection Agency has reviewed the draft programmatic environmental impact statement regarding Development Policy Options Naval Oil Shale Reserves, Garfield County, Colorado and has the following suggestions for your consideration. This environmental impact statement, to help in making policy decisions, should include an explicit discussion of various reasons why the Naval Oil Shale Reserve might be developed. The EIS should analyze the criteria for deciding whether or not the Naval Oil Shale Reserve (NOSR) shall be
11-1 developed. Such criteria should include the yearly level of private industry shale oil production that would be considered acceptable before a decision to develop NOSR lands would be initiated. The specific objectives for reducing social and environmental impacts that the government would like to achieve during this process should be enumerated. For instance, DOE should consider developing NOSR lands primarily for the purpose of promoting technology which has the least damage to the environment. EPA concurs with DOE's recommendation that upon a decision by Congress to develop the Naval Oil Shale Reserve lands a site specific environmental impact statement would be necessary to analyze the detailed impacts in that regard.

Of primary concern to EPA regarding the development of the oil shale industry is the characterization of pollutants and the demonstration of appropriate control technology in order to ensure a clean industry. Of special importance is the identification and eventual control of materials that can cause cancer and lung disease. Possible hazards include potential cancer causing compounds in the shale retort residual streams and toxic substances in the products and by-products. Of utmost interest to EPA is the potential impact to the community at large due to the release of polycyclic organic materials (POM). A recent report by the GAO suggests that exposure to POM's in the oil shale industry may act synergistically with ultra-violet radiation exposure on the Colorado plateau to increase the risk of skin cancer. Such potential health hazards serve to reiterate EPA's request that the Department of Energy withhold the development of the naval oil shale reserve pending the outcome of industry initiatives in the oil shale industry. Through those initial industry initiatives answers can be obtained to some of the current unknowns with respect to the protection of public health for those involved in the production of oil shale.

The financial results presented on pages 3-31 to 3-34 indicate an optimistic financial picture for oil shale development. Figure 3-11 shows
11-2 that the highest selling price required by the leasing case (highest industry risk) is $26 per barrel in order to return 15% to industry on their

investment. This price is well below the current market. Thus it appears that the free market system may be sufficient to initiate an oil shale industry.

11-3 The Final EIS should display, through a comparative analysis, the projected total costs per barrel associated with all of the alternatives considered, not just for oil shale. This cost range would be an important way to present the capital resource tradeoffs involved among the alternatives.

11-4 The draft programmatic impact statement indicates that DOE has initiated actions to pursue federal reserve water rights. The alternatives and specific actions taken in regard to this action should be included in the final impact statement. EPA suggests that DOE may wish to coordinate with the Water and Power Resources Service to see if water may be available in conjunction with efforts to reduce Colorado River Salinity. WPRS is currently conducting studies to determine whether or not saline groundwater within the Colorado River system might be utilized in the oil shale industry as a mechanism for both reducing salinity and enhancing energy recovery.

11-5 EPA concludes that provided DOE selects the "no action" alternative and delays the development of naval oil shale reserves, this action should be rated in the category LO-1. This means EPA has no objections and requires no additional information, if the Department of Energy proposes to delay the development of naval oil shale reserves until the outcome of private industry initiatives are determined. Please contact Weston Wilson of my staff at FTS 327-4831 if we can be of further assistance in this matter.

Sincerely yours,

Roger L. Williams
Regional Administrator

RESPONSE SET 11

11-1 Refer to the response to comment 2-7.

11-2 The financial picture projected for oil shale development was based upon the cost figures made public in 1979 and thus cannot be compared directly to current market prices in 1981 because of the high rates of inflation experienced in the last few years. The financial picture projected today would suggest prices in the range of 20% to 30% higher than those contained in the report.

Analyses which project future costs and prices for synthetic fuels and other commodities are inherently inexact because of the magnitude of the uncertainties present in estimating the future. The costs projected here are well within the range of other publicly available estimates by responsible analysts and are considered adequate for the purposes of the EIS.

The observation that the relationship between the projected cost/price levels for shale oil fuel products and current market prices may be sufficient for free market initiation of an oil shale industry is not uncommon. It is a conclusion that can be readily drawn upon a cursory examination of the risks facing the potential project developer as he views an uncertain future of 20 to 30 years. However, price risk is but one of a series of risks that require assessment prior to a decision to commit the large amounts of capital necessary for the implementation of a large scale synthetic fuels project. Few project developers appear to have sufficient confidence in the future and in oil shale technology to initiate development. A continuing perception of price parity in the future market place for shale oil products may not be a sufficient condition to promote broad scale oil shale development.

11-3 A comparative analysis of the projected total costs per barrel associated with all the EIS alternatives is not considered to be useful in the context of this EIS for NOSR 1.

The results of private sector consideration of alternatives would become evident in the responses the Government would receive to an invitation by the Government to the private sector to participate in the development of the property under specified terms and conditions.

11-4 Following the resolution of threshold jurisdictional questions (see United States v. District Court in and for Water Division No. 5, 401 U.S. 527 (1971)), the United States submitted its claims regarding water rights for a NOSR development project in Water Division 5. At the time the Department of Justice filed its water claim on behalf of various Federal agencies with operations in Water Division No. 5, it was envisioned that production from NOSR 1 might go as high as one million barrels of shale oil a day, with a water requirement of 200,000 acre feet per year. A priority date of 1916, the year NOSR 1 was withdrawn by the President, was claimed based on the Federal Reserved Water Rights doctrine. Because the water claimed for the NOSRs could not be quantified specifically at that time, as were the other Federal claims, the NOSRs claims were held in abeyance and were not heard on their merits by the appointed Master Referee. Substantial quantifications of water requirements have been made since the claims were first filed, and the overall production estimates from NOSR 1 have been reduced.

In its preparation of development options and the Draft Programmatic Environmental Impact Statement, the Department of Energy has considered the quantity of water which would be necessary to proceed with oil shale production of NOSRs 1 and 3. To date, amended or renewed applications for water have not been filed in Water Division No. 5. In studying alternative sources, the Department is also considering the possibility of purchasing water from the Ruedi Reservoir by negotiating with the Water and Power Resources Service. Another alternative is to acquire the water through condemnation. No firm commitments or decisions have been made.

11-5 No response is required for this comment. This is precisely the course of action DOE now proposes regarding NOSR 1 development.

charge of the [illegible]

The majority of private sector [illegible] could be [illegible] in the [illegible], the Government would receive [illegible] invitation by the Government [illegible] the private sector [illegible] in the development of the property under specified terms and conditions.

[illegible] With the [illegible] of [illegible] jurisdictional questions (the United States v. District Court in and for Water Division No. 5, 401 U.S. 527 (1971)), the United States submitted its claims reserving water rights for a NOSR development program in Water Division No. 5. At the time the Department of Justice filed its water claims on behalf of various Federal agencies with [illegible] Water Division No. 5, it was estimated that production from NOSR 1 might go as high as one million barrels of shale oil a day, with a water requirement of 120,000 acre feet per year. [illegible] NOSR 1 was [illegible] by the President and claims based on the Federal Reserved Water Rights doctrine, because the water claimed for the NOSRs could not be quantified [illegible] at that time [illegible] other Federal claims, the NOSR claims were held in abeyance and were not heard on their merits by the [illegible] Water [illegible]. Substantial quantification [illegible] water requirements [illegible] since the claims were [illegible], and the [illegible] from NOSR 1 [illegible] reduced.

In the preparation of development options and the Draft Programmatic Environmental Impact Statement, the Department of Energy has examined the quantity of water which would be necessary to proceed with [illegible] construction of NOSR 1 and 3. [illegible] applications for water [illegible] have been filed in Water Division No. 5 [illegible], the Department is also considering the possibility of purchasing water from the Ruedi Reservoir by [illegible] with the Water and Power Resources Service. Another alternative is to acquire the water through condemnation. No firm commitments or decisions have been made.

United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

ER-80/1368

JAN 6 1981

Mr. Donald Silawsky
Environmental Project Manager
Naval Petroleum and Oil
Shale Reserves
Department of Energy
Washington, D.C. 20461

Dear Mr. Silawsky:

12-1 We have reviewed the draft environmental statement for Development Policy Options, Naval Oil Shale Reserves (NOSR-1), Garfield County, Colorado. The scope of the statement is confusing, but basically appears to include whether to develop the 35,000-acre NOSR-1 and, if so, under what institutional and financial mechanisms. It is indicated that a site-specific environmental statement is being prepared for the leasing and development of appropriate NOSR-1 lands and is to be released shortly. In view of our extensive responsibilities in this area and the serious concerns we have 12-2 regarding adequacy of the document we have reviewed, we request that this Department be a cooperator in preparation of both the final statement for Development Policy Options and site-specific tract development.

12-3 It is not clear how this proposal would relate to possible leasing options now under review by this Department. The statement correctly notes Interior's recent decision to continue the oil shale prototype program by offering up to four more tracts to encourage multi-mineral development and different processing technologies. At the same time, a permanent oil shale leasing program is to be developed with lease sales possible in Utah before 1987. Along with this, the 15-year moratorium on Federal tar sands leasing has been lifted, and we will evaluate possible leasing of tracts in Utah.

Some basic program concepts need to be clarified. It is stated that development would help attain the President's goal of 400,000 barrels per day of oil shale production by 1990. Yet, review of the development schedule indicates that no production would be achieved prior to 1990. The full design capacity of 50,000 bbl/d would probably not be attained until 1991 or 1992.

The statement that policy developed from this document will be implemented if there is no meaningful development of privately owned oil shale in the next 18 months needs to be clarified. The term "meaningful development" has not been defined. There is no analysis of current or proposed private oil shale developments and the likelihood that desired production targets could be achieved. This is a major failure of the document.

12-4 In the discussion of Alternative Liquid Fuel Sources, it is not clear how these would substitute for development of NOSR-1 unless DOE is considering possible incentives to encourage their development beyond the level which is already underway or planned. Conservation is already national policy; what specific and presently unused measures are proposed? Private industry is already active in oil shale development on leased and private lands; could the development proposed for NOSR-1 be carried out on one of these industry-operated tracts? Enhanced Oil Recovery will be used where technologically and economically feasible; perhaps DOE could either develop new technology or provide economic incentives. A program of OCS development in the Gulf of Mexico is already being conducted by Interior; it is not clear how it could be expanded beyond its technological or economic limits. Tar Sands was discarded as an alternative, yet this Department is considering possible leases in Utah. Liquifaction and Biomass/Alcohol are being actively pursued by private industry. Onshore oil and gas development was omitted; was this deliberate or an oversight? In any event, unless exploitation of these is to be augmented in some manner beyond the otherwise normal levels of development, it is not clear how they can be identified and evaluated as alternatives. These are presently being developed.

Any development of NOSR-1, or other private or leased oil shale lands in the Rocky Mountain area will undoubtedly require rights-of-way or other land use approvals by this Department. Therefore, we are concerned that NEPA documents address our needs to the extent possible. Besides the questions we have raised regarding scope and alternatives, we have identified the following problems in regard to specific resource treatment.

The document is silent, or extremely sketchy at best, in regard to several items of major concern in evaluating possible impacts that may accrue to public lands and resources if development were to occur. Specific consideration of the following is mandated by Executive Orders and/or CEQ regulations:

- Flood plains or flood hazards
- Threatened or endangered plant or animal species
- Cultural resources
- Prime or unique farmlands
- Visual resources
- Socio-economic considerations
- Wilderness review

12-5 Treatment of wildlife resources is inadequate, both in evaluation of the impacts from development of NOSR-1 and in discussion of other alternatives. Analyses as to impacts on this resource are insufficient to provide any rational basis of comparison between alternatives. The information available in this statement neither precludes nor lends preference to development of NOSR-1. We have serious concerns regarding possible serious wildlife impacts from oil shale development and believe this should be reflected in any environmental review of such projects. This is a new technology and the effects on wildlife and the environment that support it are not known. Much research and development remains to be done for both pilot and commercial oil shale operations. We recommend that development of NOSR-1 be handled under stringent environmental stipulations which mandate that the full environmental consequences of development be monitored for identification and possible mitigation.

12-6 The draft misstates the situation regarding loss of public revenue if the government were to own all or part of the development project (page 3-25). The severance tax and mineral lease royalty refunds to the State would also be affected by government ownership. These receipts are the primary funding of State programs, to assist communities affected by energy development, and their loss deserves more discussion.

The property tax is the most important source of revenue for dealing with impacts and its loss would require a sizable program of special Federal assistance. Payment in Lieu of Taxes (PILT) cannot be considered even partial compensation for such a loss. Any PILT that Garfield County already receives would be unaffected by future development of Federal lands, as payments are based on "entitlement" acres. It is not clear that the NOSR-1 is entitlement land as specified by Public Law 94-565.

12-7(A) The need for a net energy analysis of the proposal and alternatives was recognized but was not presented. 12-7(B) Other impacts identified received only cursory treatment. 12-7(C) The conservation alternative was limited to only motor fuels used in automobiles. Certainly, other conservation measures would "produce" liquid fuel by reduced consumption. Public transit, alternative fuels for electric power generation (coal, refuse, or wood waste) or additional hydroelectric power production were not addressed. Similarly, the use of nuclear fuel to "produce" liquid fuel by conservation was not addressed. It is obvious that the range of alternatives is artificially narrow.

12-7(D) In terms of impact analysis, development of the NOSR-1 could involve technology other than room and pillar. The variety of in situ processes should be analyzed. In other words, NOSR-1 development involves more than Federal financial participation.

12-8 The comparison of air pollution emissions and water requirements between the NOSR-1 and the Colony Oil Shale Project, which is used as a technology alternative, appears critically flawed. The air pollution emissions for the NOSR-1 development are represented as ranging from one-half to one-fifth of the emissions from the Colony Development (pages 3-13, 3-14, 5-3, and 5-15). This comparison may be biased by the inclusion of shale oil upgrading facilities for the Colony operation and no upgrading facilities for the NOSR-1 development. We recommend that the emissions for Colony be based on data provided in the Prevention of Significant Deterioration (PSD) permit and not on data provided in the Colony environmental statement. Water requirements for the NOSR-1 are represented as one-half the water requirements for the Colony development (pages 3-17, 5-4, and 5-15). The rationale for this is not clear.

12-9 Comparisons should be made of resource recovery between the different technology alternatives. The comparison of any liquid-fuel development options should consider the ultimate recovery efficiency of the in-place resource in addition to technologies that may be more environmentally favorable.

We appreciate the opportunity to review and comment on this document. Our staff is available to assist as appropriate in the areas where we have expressed concern. In addition, we would like to meet with your staff as soon as possible to discuss the scope and content of the site-specific environmental statement for development of NOSR-1. This should ensure effective coordination between our two departments at an earlier stage of this project phase. Please contact Tom Loomis, Office of Environmental Project Review (343-8661) to arrange a mutually agreeable meeting time and place.

Sincerely,

James

James H. Rathlesberger
Special Assistant to
Assistant SECRETARY

SPECIFIC COMMENTS

Page 1-5 states that Appendix E contains a list of issues raised at the February 5th and 7th scoping meetings. There is no such list.

Page 1-7, "High land use for biomass/alcohol is due to the large number of individual plants." The subject matter of the paragraph in which this sentence appears may lead some readers to believe that the "plants" mentioned are the kinds that grow and contain chlorophyll. This is not true; the "plants" are industrial.

Page 3-13. The vertical scale of each graph should be in units of 1,000 tons per year.

Page 3-16. There is no description in the environmental statement of the "most water-intensive process" being considered for the NOSR-1.

12-10 Page 3-17. There has been no indication in the statement narrative that other technologies are being considered for development of the NOSR-1.

Page 3-17. The single asterisk footnote discusses enhanced oil recovery (EOR), yet is placed in the OCS column.

Page 3-17. The land use requirements legend defines areas for facilities and solid waste disposal, yet only solid waste disposal acreages are indicated for the "NOSR" and "Other Oil Shale" columns.

Page 3-18. The "Availability of Water for Oil Shale and Coal Gasification" reference should include author (Colorado Department of Natural Resources) and date (October 1979).

Page 4-1. Grand Valley Colorado, is located southwest of NOSR-1. It may be noted that the community of Grand Valley has recently changed its name to Parachute.

12-11 Page 4-4, paragraph 2. The discussion on vegetation needs to discuss rare plant species listed or being considered for Federal listing found on Naval Oil Shale Reserve.

12-12 Page 4-7. The statement that "there are no faults in the basin" is incorrect. There are several persistent northwest-trending en echelon fault systems in the Piceance Basin.

12-13 Page 5-5, paragraph 3. Discussion about processing water needs to include possible impacts of fluoride and boron. These chemicals were left out or only mentioned briefly. They should be discussed in detail.

12-14 Page 5-6. Discussion left out fluoride, a most important leachate.

12-15 Page 5-7, paragraph 2. Discussion on land use being effected did not discuss wildlife habitat being lost in utility corridors.

12-16 Page 5-7. "The hazards generally associated with coal mining.... are less likely to occur in oil shale mining..." We could agree with this statement if it pertained to roof falls, would question it if it pertained to dust, and we disagree with its application to methane generation, fire or explosions.

12-17 Page 5-7. Land use impacts should also include powerline corridors and site access routes (Parachute Creek or Cow Creek). These are discussed for Colony operations (pages 5-17 and 5-19).

12-18 Page 5-8, Ecosystem. Did not discuss raptor habitat. The Colorado River cutthroat, a state endangered species and under review for Federal listing, was not mentioned. The entire discussion of the environmental ecosystem is extremely brief and needs more development.

12-19 Page 5-15. Table 5-5 only presents one production level, although the narrative indicates that two production levels are presented.

12-20 Page 5-16, paragraph 4. Parachute Creek contains Colorado River cutthroat trout which is a state listed endangered species.

12-21 Page 5-18, Ecosystem Impacts. The dicussion on plant species needs to be amended as follows: Two species Phacelia submutic, scorpion weed and Festuca dasyclada, sedge fescue are being reviewed for Federal listing and do occur in the region. The state listed species Aquilequa barnabyi, Uinta Basin hookless cactus, may also occur in the Naval Oil Shale Reserve. Also, in case of an upset condition, you would possibly damage air and water by pollution. This would effect the wildlife. In the discussion, it says there will be no effect.

12-22 Page 5-19, paragraph 1. Discussion on construction and effects on fish populations in Parachute Creek due to siltation states that this effect would be temporary. This is incorrect since aquatic fish food organisms will continue to be constantly effected by siltation. If this impact continues down drainage to the Colorado River, it may effect endangered fish species in the river.

12-23 Page 5-24. Line 16 does not include the "BPD" production level.

Page 5-27. Table 5-7 footnote should be "90 percent of the HC values."

12-24 Page 5-29. Discussion on Ecosystem Impact. There is no real way to make adequate comparisons with other energy options. This discussion is without data for comparison with the Naval Oil Shale Reserve option.

Page 5-35, Ecosystem Impacts. See statement for page 5-29.

12-25 Page 5-37. There is confusion whether the biomass reference case consists of 15 plants or 14 plants.

Page 5-38. In the narrative and in Table 5-10 there is confusion regarding 15 or 14 biomass plants.

12-26 Page 5-41, Ecosystem Impacts. There is no foundation given for the speculation that corn will degrade the air more than other crops. This subject needs to be expanded.

12-27 Page 5-47. Wildlife management and recreational use are not discussed for any option for the social economic scenarios.

12-28 Page A-1. Green River Formation oil shale is of Tertiary age and not Devonian or Mississippian.

12-29 Page A-2, paragraph 2. Did not discuss status of rare plant species occurring on the tract. The discussion of endangered wildlife species is misleading. The species identified are either transients to the area or are only possible residents of the region. Golden eagles occur in the area. They are provided protection by the Bald and Golden Eagle Act, yet no discussion of possible detrimental impacts of development of the Naval Oil Shale Reserve is presented.

12-30 Page B-6. It is indicated that the NOSR-1 technology and design includes an upgrading plant, but this is not stated in the narrative on pages 5-2, 5-3, C-1, and C-2.

RESPONSE SET 12

12-1 Refer to the responses to comments 2-6 and 2-7.

12-2 DOI and DOE agreed to an informal cooperative arrangement in preparing this final EIS whereby DOI reviewed the final document prior to publication and recommended revisions, which were made by DOE. Any future NEPA compliance work for NOSR 1 will be coordinated with DOI.

12-3 See the response to comment 3-5.

12-4 The question regarding alternative liquid fuel sources being valid alternatives raises a significant issue if viewed at the national level. The document itself mentions this issue in Section 2.

When viewed in the context of a NOSR oil shale programmatic EIS, which is required to be basically an environmental document, the comparison of alternative liquid fuels in terms of their environmental impacts seems both logical and appropriate.

12-5 As indicated on p. 4-13, the discussion of NOSR 1 flora and fauna was of necessity generalized in the EIS since site-specific studies were to be performed later and reported in a site-specific NEPA document. Site-specific data on flora and fauna have been obtained since the draft was written and have been included in the final document. This expansion will mean that the description of existing wildlife and wildlife impacts is more detailed for the NOSR case than for other alternatives. This is considered appropriate since (1) NOSR development is the primary action being considered by the EIS, (2) less-than-general descriptions of the sites affected by the reference case alternatives would cease to be representative of the locations which those alternatives may affect, and (3) detailed EISs are available for many of the alternatives other than NOSR 1 development.

12-6 No revenue to local government is currently derived from the NOSR tract. Under current Federal Law, all moneys accruing to the United States from lands within the Naval Petroleum Reserves are deposited in the Treasury as "miscellaneous receipts."

It is true that the Naval Petroleum Reserves, including NOSR, are not part of the entitlement lands from which Colorado counties receive payments on public lands under Public Law 94-565, payment in lieu of taxes (PILT), the Mineral Lands Leasing Act, the Taylor Grazing Act, the Federal Power Act, and from the United States Forest Service. Currently, Garfield County receives the maximum PILT payment allowed by a formula based on population and acres of entitlement land in the county. Total revenue in 1980 to the county for entitlement lands was $550,000. $22,800 was for payment in lieu of taxes; the balance was derived primarily from revenue from mineral leasing and grazing permits.

Revenues to local government units which may become available in the future with development of the NOSR tract will depend on the development policy selected (e.g., leasing, etc.), if any development option is, in fact, selected, and the terms and conditions incorporated in the implementation of the selected development policy.

12-7A Refer to response 3-8.

12-7B Impacts were identified and analyzed in a way which could be applied consistently for all alternatives to provide a common basis for decision making. The level of analysis presented is thought to be adequate for the programmatic decisions to be made. Several specific analyses have been expanded and/or revised in response to other comments. Detailed impact analyses of NOSR development will be performed prior to initiation of development when site- and project-specific information is available.

12-7C The alternatives used were selected because they all produced (or conserved) liquid fuel directly. In our opinion, the conservation alternative selected was a reasonable representative of liquid fuel conservation concepts in terms of environmental impacts, although there are no off-setting impacts that would be present in, say, mass transit. Substitution, such as the use of nuclear fuel, hydroelectric power, and the like, instead of a liquid fuel, as suggested in the comment, would expand the document to include all possible energy sources, substitutions, and conservations. Even if such an analysis were practical, DOE believes that it would obscure the intent of the document.

12-7D Our analysis of oil shale mining methods on NOSR 1 has indicated that room-and-pillar underground mining is by far the most suitable for that part of the Piceance Basin. In situ processes were analyzed and were found to be less desirable for the NOSR resource.

12-8 The data from the Colony PSD permit were used in the final EIS. Data for water requirements are accurate for the processes used for NOSR and Colony. The differences in the types of processes used for each case account for the differing water requirements.

12-9 Ultimate recovery of in-place resource is not an accurate measure of efficiency. The recovery of an in-place resource varies with economics and technology development. It is a constantly changing parameter and does not lend itself to decision-making in a time frame such as that considered by this EIS.

12-10 Editorial changes have been made in the sections indicated in the comment.

12-11 See response to comment 12-5.

12-12 This comment correctly notes that the draft EIS statement that "there are no faults in the basin" is incorrect. The Piceance Basin, the structural basin which contains oil shale deposits in several locations, does have a prominent system of faults that crosses the basin about 20 miles northwest of the NOSR 1 property. Regularity of structure contours within the Reserve suggest that large faults are probably not present in the NOSR. One small fault is located on the NOSR in an extreme northwest area of the Reserve. This fault is 1500 feet long on aerial photos and is not considered a hazard to development, but may provide a channel for the flow of water into underground shale mining operations in the vicinity of the property. No large faults are found on the NOSR. There are no restrictions anticipated on mine locations due to faults in the area.

12-13 The potential hazards of a process water spill were addressed in general terms. Discussion of specific pollutants such as fluorides or boron is more appropriate to a site-specific EIS.

12-14 The soluble fluoride compounds in any leachate of spent shale are intended to be included in the group referred to as "dissolved solids." Discussion of any of the fluorides or the group as a whole is more appropriate to a site-specific EIS.

12-15 The ecological impacts section and land use section were revised to include a brief discussion of corridor impacts. Specific habitats to be affected by corridors cannot be addressed in this document since the location of corridors is unknown.

12-16 The statement on page 5-7 of the draft EIS is supported by a large volume of literature on the subject. A good reference is the paper "Oil Shale Mining - Plans and Practices" by Robert B. Crookston and David A. Weiss.

12-17 The discussion of land use impacts has been modified to address this comment, i.e., land use impacts of utility corridors, access corridors and pipeline corridors have been mentioned.

12-18 The discussion of ecology has been expanded and addresses the raptor habitat and Colorado River Cutthroat.

12-19 Table 5-5 has been modified to include the 200,000 bpd production level.

12-20 Revisions to this section address these issues.

12-21 It is not clear whether the comment in indicating the presence of the scorpion weed and the sedge fescue on the Colony property or in the generalized region. Since the discussion of endangered plant species refers to the Colony property only, it will continue to rely upon information specific to the Parachute Valley. However, the discussion of vegetation on the NOSR 1 property was revised to include recent onsite survey results. Among other things, the Festuca dasyclada and the Aquilegia barnebyi were observed on the NOSR 1 property.

12-22 This sentence was modified for greater clarity. It is not evident that the effects on siltation will be permanent since natural stream action is capable of removing excess silt over time and because the stream is periodically stocked. Obviously an extreme increase in siltation above normal rates could have a devastating effect on aquatic species. However, proper controls should be capable of preventing inordinate sedimentation rates.

12-23 Editorial changes have been made.

12-24 The information presented in this section is intended to describe the most significant potential ecosystem impacts associated with OCS oil drilling in the Gulf of Mexico. The lack of easily comparable data vis-a-vis NOSR 1 is primarily the result of major differences in the types of ecosystems which are addressed in the two cases (terrestrial and marine). It is believed that the major issues were adequately addressed in the OCS discussion. See also response to 12-5.

12-25 The text has been modified to clarify the situation.

12-26 The discussion does not assume that the corn degrades air quality more than the cultivation of other crops. However, since the production of ethanol by the methods described would require corn cultivation, the associated air quality impacts (particulates, etc.) must be included as an impact of this alternative. As discussed in the "Major Uncertainties" section, corn used for ethanol may in fact come from land which already produces corn (or other crops). The fugitive emissions from this land would not represent increases in air quality degradation over current levels. Nevertheless they do represent emissions which are associated with the biomass alternative.

12-27 Outdoor recreation resources in the NOSR 1 study area (Rio Blanco, Mesa, and Garfield County), particularly the White River National Forest, could be adversely impacted by heavily intensified use on the part of new in-migrant work force populations. National forest personnel in Rifle in western Garfield County have publicly expressed their concern that forest and wilderness lands in proximity to NOSR 1 are already subject to overuse as a result of new population growth in the Rocky Mountain Regions.

12-28 Text has been amended.

12-29 Revisions to the description of the affected environment (Chapter 4, Section 4.1) respond to this comment.

12-30 The discussion of the NOSR reference case plant has been amended to more clearly describe the upgrading process.

COMMENT SET 13

The Department of the Interior has requested that Comment letter 13 not be included in the final EIS. All comments in this set were reviewed by DOI's Washington staff, and included in Comment set 12 as appropriate.

RESPONSE SET 14

Comment set 14 was an informally transmitted set of grammatical and editorial suggestions which have been incorporated in the final EIS.

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT
REGIONAL/AREA OFFICE
EXECUTIVE TOWER - 1405 CURTIS STREET
DENVER, COLORADO 80202

REGION VIII

RECEIVED
NOV 4 12 00 PM '80
DIRNAVPETRES
WASH., D.C.

October 28, 1980

IN REPLY REFER TO:

8SOQ

Mr. C.M. Wong
U.S. Department of Energy
Federal Building, Room 3344
12th & Pennsylvania Avenue, N.W.
Washington, D.C. 20461

Dear Mr. Wong:

Thank you for the opportunity to review and comment on the draft Environmental Impact Statement (EIS) DOE/EIS-0068, Programmatic Development Policy Options, Naval Oil Shale Reserves, Garfield County, Colorado.

Your draft has been reviewed with specific consideration for the areas of responsibility assigned to the Department of Housing and Urban Development (HUD). The review considered the proposal's compatibility with local and regional comprehensive planning and impacts on urbanized areas.

15-1 Our review found that the socioeconomic impacts on the local community of Rifle, Colorado were not adequately addressed. Enclosed are the agreed to stipulations made by Mobil Oil Corporation, in regard to the energy impacted community of Gillette, Wyoming. These stipulations should also alert you to areas of impact which need more discussion in your EIS. It is suggested that the Mobil stipulations be considered by all energy companies.

If you have any questions regarding these comments, please contact Mr. Carroll F. Goodwin, Area Environmental Clearance Officer, at FTS 327-3102 in Denver.

Sincerely,

Raymond D. McKinney

Raymond D. McKinney
Director
Program Planning and Evaluation

Enclosure

SEPTEMBER 19, 1980

TO: ALL INTERESTED PARTIES:

THE DRAFT ENVIRONMENTAL IMPACT STATEMENT (EIS) ON THE PROPOSED ROJO CABALLOS MINING AND RECLAMATION PLAN IS ENCLOSED FOR YOUR REVIEW AND COMMENT.

REGION V OF THE OFFICE OF SURFACE MINING (OSM), AS THE LEAD FEDERAL AGENCY, AND THE U.S. GEOLOGICAL SURVEY (USGS) PREPARED THIS DOCUMENT. THE ASSISTANT SECRETARY OF THE INTERIOR FOR ENERGY AND MINERALS WILL USE THIS DOCUMENT AND OTHER INFORMATION TO MAKE A DECISION ON MOBIL OIL CORPORATION'S APPLICATION TO MINE COAL ON FEDERAL LAND IN GILLETTE, WYOMING. THE DEPARTMENT IS REQUIRED TO MAKE A DECISION ON A COMPLETE MINE PLAN APPLICATION BASED ON A WRITTEN FINDING THAT THE COMPANY HAS COMPLIED WITH SECTION 510 OF THE SURFACE MINING CONTROL AND RECLAMATION ACT OF 1977 (P.L. 95-87).

THE ALTERNATIVE ACTIONS THAT HAVE BEEN EVALUATED IN THIS EIS ARE:

- APPROVAL OF THE MINING AND RECLAMATION PLAN WITH STIPULATIONS REQUIRED BY STATE AND FEDERAL LAW AND A STIPULATION TO MITIGATE SOCIO-ECONOMIC IMPACTS
- APPROVAL OF THE MINING AND RECLAMATION PLAN WITH STIPULATIONS REQUIRED BY STATE AND FEDERAL LAW
- DISAPPROVAL OF THE MINING AND RECLAMATION PLAN
- DEFER ACTION
- NO ACTION

THE EIS IDENTIFIES THE DEPARTMENT'S CURRENT PREFERRED ALTERNATIVE AS APPROVAL OF THE MINING AND RECLAMATION PLAN WITH THE STIPULATION REQUIRED BY STATE AND FEDERAL LAW AND A STIPULATION TO MITIGATE SOCIO-ECONOMIC IMPACTS.

OSM IS LOOKING FORWARD TO RECEIVING SUBSTANTIVE PUBLIC COMMENT ON THE ANALYSIS OF ALL ALTERNATIVES. OSM REGION V'S FINAL RECOMMENDATION TO THE ASSISTANT SECRETARY OF THE INTERIOR FOR ENERGY AND MINERALS WILL BE BASED ON THE PUBLIC COMMENTS RECEIVED ON THIS DRAFT EIS AND ANY NEW INFORMATION ON THE PROPOSED MINE AND/OR MINE SITE. THE FINAL RECOMMENDATION AND ANY MODIFICATIONS TO THE DRAFT EIS WILL BE INCLUDED IN THE FINAL EIS.

THE DRAFT EIS (ONE VOLUME) IS AVAILABLE FOR REVIEW AT THE CAMPBELL COUNTY COURTHOUSE, THE CAMPBELL COUNTY RECREATION CENTER, GILLETTE, WYOMING, AND AT THE STATE OF WYOMING, DEPARTMENT OF ENVIRONMENTAL QUALITY (DEQ), 401 WEST 19TH STREET, CHEYENNE, WYOMING. PUBLIC COMMENTS MUST BE RECEIVED BY NOVEMBER 19, 1980. THE DRAFT TECHNICAL AND ENVIRONMENTAL ANALYSIS HAS NOT BEEN DISTRIBUTED WITH THIS EIS. ANYONE MAY REQUEST THIS TECHNICAL DOCUMENT FROM OSM AT THE REGION V OFFICE.

A PUBLIC HEARING ON THE EIS WILL BE HELD AT THE CAMPBELL COUNTY RECREATION CENTER, ROOM C, IN GILLETTE, WYOMING, ON NOVEMBER 5, 1980. THE HEARING WILL BE CONDUCTED IN TWO SESSIONS: 1:00-4:00 P.M.; 7:00-9:00 P.M. ANYONE INTERESTED IS INVITED TO ATTEND AND GIVE HIS/HER COMMENTS ON THE EIS.

PUBLIC COMMENTS AND ANY QUESTIONS SHOULD BE ADDRESSED TO:

ROBERT SCHUENEMAN
OFFICE OF SURFACE MINING RECLAMATION AND ENFORCEMENT
BROOKS TOWERS
1020 15TH STREET
DENVER, COLORADO 80202

DONALD A. CRANE
REGIONAL DIRECTOR

Reclamation

Mobil's reclamation plan provides for reestablishment of a vegetative system comparable in cover and density to that now existing on the permit area. The applicant proposes to return the land to a postmining use of livestock grazing and wildlife, which is reflected in the seed mixtures and plant materials. Six of the sediment ponds would remain on the site following mining to provide for stock and wildlife uses. These land uses conform with the historical and premining land use.

Bulldozer-mounted rippers or agricultural tillage equipment would prepare the surface of the regraded overburden for topsoiling. Topsoil would be replaced in lifts of approximately 1 foot thick until sufficient thickness (table A-3) has been obtained to allow the vegetative growth necessary for the postmining land use. Between 2 and 5 feet of topsoil material, including at least 6 inches of A-horizon soil on top, would be distributed over the reclaimed areas. Proper combinations of soil amendments would be used to develop optimum plant growth under prevailing conditions at the time of reclamation. The final topography (fig. IV-1) would be similar to present topography.

The applicant has selected two permanent seed mixes: rangeland revegetation mixture, deep soil mix, for reclaimed areas with 3 to 5 feet of topsoil; and rangeland revegetation mixture, medium soil mix, for reclaimed areas with 2 to 3 feet of topsoil (table A-4). Additional seed mixtures are proposed for temporarily revegetated backfill and for stabilization. In addition to seeding, shrub transplants or hand-planted tublings would be made in three mixtures: shrubland revegetation mixture, sagebrush; shrubland revegetation mixture, mesic; and shrubland revegetation mixture, mesic conditional (table A-4). Big sagebrush and silver sagebrush would be transplanted at rates of 1,160 plants per acre and 40 plants per acre, respectively. The remaining shrub species would be segregated by species in patches and in densities comparable to the current average density of all shrub species, i.e., 1,200 plants per acre. Forty plains cottonwood trees would be planted with a tree spade around the two large permanent ponds on the western half of the site. A preparatory crop (wintergraze) would be used on temporarily revegetated overburden areas (25 pounds of pure live seed per acre) and would be used in conjunction with additional perennial species for all overburden and topsoil stockpile stabilization areas.

Mobil states that seeding would follow topsoil placement as close as possible (maximum 45 days) within the constraints of seasonal variation in accessibility and soil moisture conditions. Seeding would be done during the first normal period of favorable planting conditions (March through May or September through early December). All seeding would be accomplished by broadcast or drill seeding. Determination of the seeding method for a specific area during a specific planting season would be made on a case-by-case basis and after consultation with the appropriate regulatory authorities.

Mobil would assess the need for fertilization through a soil-testing program prior to revegetation activities.

All reseeded areas (topsoiled or revegetated overburden) would be mulched with cellulose wood fiber unless it can be demonstrated that equal or better revegetation and sediment control can be obtained without mulching. Areas of less than 8H:1V slope would be mulched at a rate of 1,500 pounds per acre; areas greater than 8H:1V slope would be mulched at a rate of 2,000 pounds per acre.

Table A-3.--Topsoil replacement depths, Rojo Caballos mine

(Note: Ranges in depths will be used to provide a transition between replacement zones and undisturbed areas)

Postmining plant community	Topsoil depth (feet)
Rangeland revegetation mixture:	
Deep soil.	3-5
Medium soil	2-3
Shrubland revegetation mixture:	
Sagebrush	2-5
Mesic	2-5
Mesic conditional	2-5

Table A-4.--Revegetation mixtures, Rojo Caballos mine

[Note: The shrubland revegetation mixtures would be superimposed on the rangeland revegetation mixtures]

Species		Seeding rate (pounds of pure live seed per acre)	Planting rate (plants per acre)
Scientific name	Common name		
Rangeland revegetation mixture, deep soil			
Grasses:			
Agropyron dasystachyum	Thickspike wheatgrass	4.0	NA[1]
Agropyron riparium	Streambank wheatgrass	3.0	NA
Agropyron smithii	Western wheatgrass	4.0	NA
Agropyron trichophorum	Pubescent wheatgrass	2.0	NA
Bouteloua curtipendula	Side-oats grama	0.5	NA
Bromus inermis	Smooth brome	3.0	NA
Calamovilfa longifolia	Prairie sandreed	1.5	NA
Elymus cinereus	Basin wildrye	1.0	NA
Koeleria cristata	Prairie junegrass	1.5	NA
Oryzopsis hymenoides	Indian ricegrass	2.0	NA
Poa compressa	Canada bluegrass	1.0	NA
Poa pratensis	Kentucky bluegrass	1.0	NA
Sporobolus airoides	Alkali sacaton	1.0	NA
Stipa viridula	Green needlegrass	3.0	NA
Forbs (legumes):			
Astragalus cicer	Cicer milkvetch	0.5	NA
Medicago sativa	Alfalfa	0.5	NA
Onobrychis viciaefolia	Sainfoin	2.0	NA
Shrubs:			
Atriplex canescens	Fourwing saltbush	2.0	NA
Rangeland revegetation mixture, medium soil			
Grasses:			
Agropyron dasystachyum	Thickspike wheatgrass	4.0	NA
Agropyron elongatum	Tall wheatgrass	2.0	NA
Agropyron riparium	Streambank wheatgrass	1.5	NA
Agropyron smithii	Western wheatgrass	4.0	NA
Agropyron spicatum	Bluebunch wheatgrass	1.0	NA
Agropyron trichophorum	Pubescent wheatgrass	2.0	NA
Buchloe dactyloides	Buffalo grass	0.5	NA
Bouteloua curtipendula	Side-oats grama	1.0	NA
Bouteloua gracilis	Blue grama grass	1.0	NA
Bromus inermis	Smooth brome	3.0	NA
Calamovilfa longifolia	Prairie sandreed	2.0	NA
Koeleria cristata	Prairie junegrass	1.0	NA
Species		Seeding rate (pounds of pure live seed per acre)	Planting rate (plants per acre)
Scientific name	Common name		
Rangeland revegetation mixture, medium soil			
Grasses:			
Oryzopsis hymenoides	Indian ricegrass	1.0	NA
Sporobolus airoides	Alkali sacaton	1.0	NA
Sporobolus cryptandrus	Sand dropseed	0.5	NA
Forbs (legumes):			
Astragalus cicer	Cicer milkvetch	0.5	NA
Onobrychis viciaefolia	Sainfoin	3.0	NA
Shrubs:			
Atriplex canescens	Fourwing saltbush	2.0	NA
Shrubland revegetation mixture, sagebrush			
Shrubs:			
Artemesia tridentata	Big sagebrush	NA	1,160
Shrubland revegetation mixture, mesic			
Shrubs:			
Salix exigua	Coyote willow	NA	around ponds
Ribes cereum	Wax currant	NA	around ponds
Rosa woodsii	Woods rose	NA	around ponds
Prunus virginiana	Common chokecherry	NA	around ponds
Trees:			
Populus sargentii	Plains cottonwood	NA	40 (total)
Shrubland revegetation mixture, mesic conditional			
Shrubs:			
Ribes cereum	Wax currant	NA	1,200
Rosa woodsii	Woods rose	NA	
Rhus trilobata	Skunkbush sumac	NA	
Artemesia tridentata	Big sagebrush	NA	
Artemesia cana	Silver sagebrush	NA	
Shepherdia argentea	Silver buffaloberry	NA	

[1] NA = Not applicable.

The reseeded areas would be protected by the fence that surrounds the mine. In addition, a fence would be constructed to the west of the affected area to allow grazing on the western part of the permit area until mining activities reach that area. Livestock would be excluded until the reseeded areas can withstand grazing pressures and have developed a productivity equal to or better than premining plant communities. The proposed postmining plant communities are shown in figure A-5.

In the areas adjacent to other mines and covered by a backslope agreement, the first operator to mine would remove the coal to the ownership line. The cut would be backfilled and the exposed slope, if any, would be graded to not exceed 3H:1V. This slope would be temporarily revegetated, using additional contouring and higher mulching rates to control erosion, and maintained until the second operator redisturbs the area. At this time, the backslope area would be backfilled and graded to the approximate original contours, allowing for lowering due to coal removal and swelling of the replaced overburden. The area would be graded to blend into the adjacent areas. During the temporary reclamation stage, any exposed coal would be covered by at least 8 feet of overburden and the elevation of the toe of the slope would be approximately the same as the top of the lowest overburden bench.

To minimize disturbances and adverse impacts to wildlife in the area, the company included vegetation of value to wildlife in their revegetation seeding mixtures (table A-4). Fencing that would facilitate deer and antelope passage in accordance with the Wyoming Game and Fish Department's recommendations would be used throughout the mine area. Boulder piles would be distributed over the area to provide shelter and den sites for mammalian predators and their various prey species, and the six stock ponds would provide habitat for amphibians and waterfowl. Powerlines would be designed to minimize impacts to raptors in accordance with REA Bulletin 61-10. Use of the company-provided bus service would reduce road kills of deer and antelope.

To mitigate destruction of a sage grouse lek in section 11, Mobil would try to move the lek to a nearby suitable area that would not be mined. During reclamation, Mobil would try to restore the lek. The reconstructed habitat would include:

- An open short-grass hilltop to serve as a potential lek.
- Dense stands of big sagebrush in close proximity to the lek site to serve as potential nesting and wintering areas.
- Grassy draws with mixed shrub cover adjacent to big sagebrush stands to serve as potential brood-rearing areas.
- Permanent water sources within one to two miles of the lek, nesting habitat, and brood-rearing areas.

Assistance to the Community

The applicant has developed a socioeconomic program to alleviate some of the proposed mine's impacts on the community. The four essential elements of this program are as follows:

- Construction worker housing,

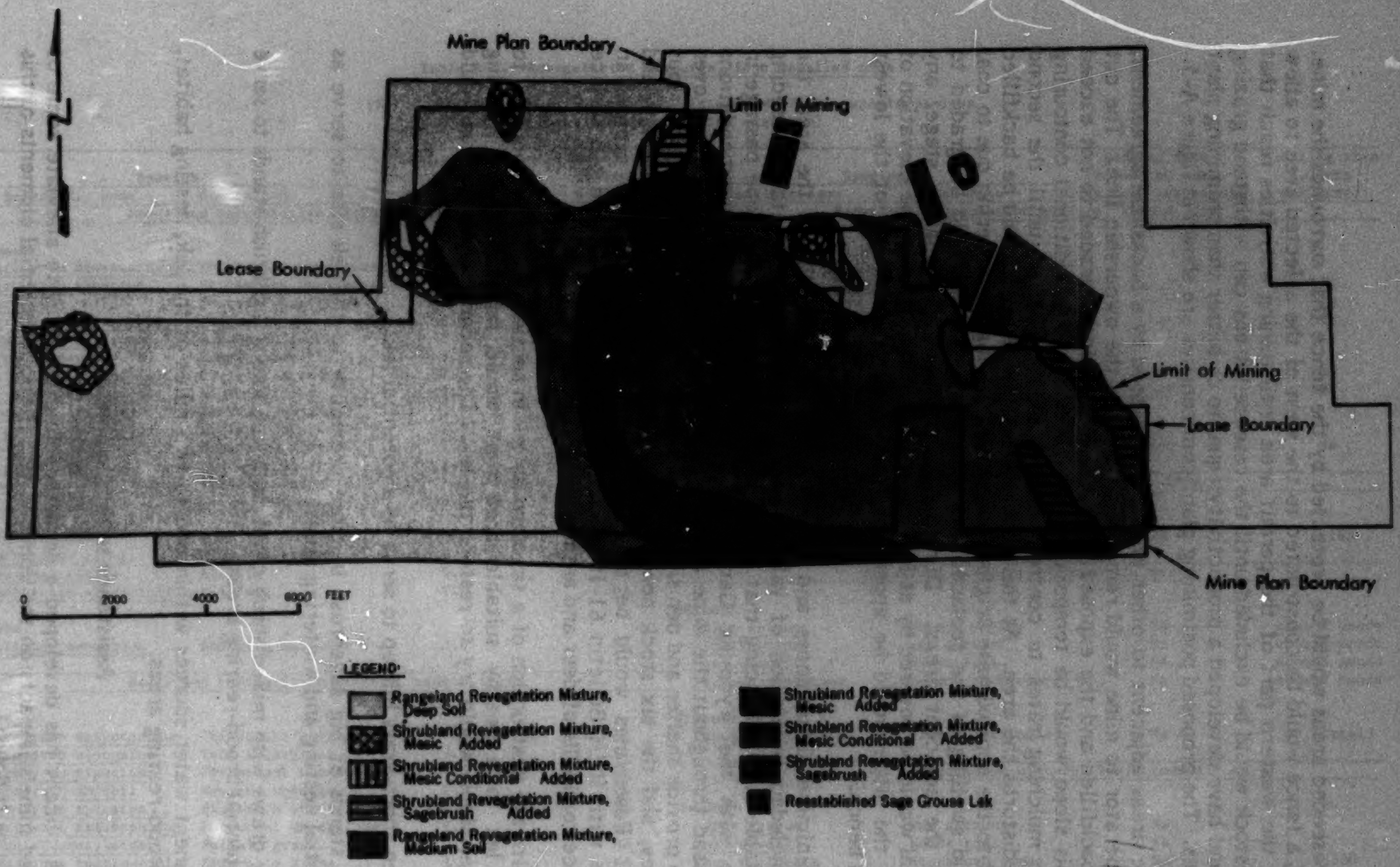
Mine Plan Boundary
Limit of Mining
Lease Boundary
Limit of Mining
Lease Boundary
Mine Plan Boundary
0
2000
4000
6000
FEET
LEGEND
Rangeland Revegetation Mixture, Deep Soil
Shrubland Revegetation Mixture, Mesic Added
Shrubland Revegetation Mixture, Mesic Conditional Added
Shrubland Revegetation Mixture, Sagebrush Added
Rangeland Revegetation Mixture, Medium Soil
Shrubland Revegetation Mixture, Mesic Added
Shrubland Revegetation Mixture, Mesic Conditional Added
Shrubland Revegetation Mixture, Sagebrush Added
Reestablished Sage Grouse Lek

Figure A-5.--Postmining plant communities, Rojo Caballos mine.
(Furnished by applicant.)

- Permanent worker relocation assistance programs;
- Assistance to the City of Gillette; and
- Related community impact mitigation measures.

Construction worker housing

The Rojo Caballos mine would employ up to 540 workers during construction. More than 20 percent of the required construction manpower is expected to come from the local area and, therefore, would not impact directly on housing availability. Most of the incoming workers would require housing in mobile home parks. The applicant would negotiate with selected park owners for pre-lease, or guaranteed space availability, agreements to ensure that locations for mine employees would be available as they are needed while, at the same time, protecting the park owner from carrying unused lots that were developed at Mobil's request.

Of the 200 to 250 total spaces to be reserved by the applicant in 1981 through 1983, 70 would be allotted for recreational vehicles, 30 would be equipped with mobile home lease units that would serve as 2- to 3-person living units, and the remaining 100 to 150 spaces would be for those workers wishing to move or purchase their own mobile homes.

Construction employment would phase down from 540 in May, June, and July of 1982 to 55 in December of 1982, at the same time that the operational workforce would be building up. As construction workers vacate their housing units, these units would become available for the permanent workers to settle in if they so desire.

Permanent worker relocation assistance programs

The majority of the permanent workers would come from outside the Gillette area. These permanent workers are projected to be mostly younger people who would not have large savings or equity in a home. The applicant plans to provide assistance to the Rojo Caballos employees to help them qualify for conventional home mortgage loans at the earliest possible date and to defray the cost of relocation. By enabling employees to purchase permanent housing, this mitigation strategy would also have the following effects:

- Expand housing development in Gillette and help maintain a balance between housing supply and demand; and
- Stimulate the Gillette economy through local involvement in housing construction and development.

The principal features of this assistance program are:

- Relocation expense.—The proposed program would be designed to cover moving expenses including commissions on the sale of housing already owned for those employees who own housing at the time they are hired. The intent is to defray expenses normally associated with moving, thus assisting permanent employees in making a mortgage downpayment in Gillette.

- Down payment assistance.—The proposed program provides for payment of a sum of money, based upon the employee's salary level, to the permanent employee when he/she selects a housing unit. This would further assist the employee who desires to purchase a housing unit in meeting downpayment requirements.

- Interest assistance.—Current high interest rates may prevent employees from meeting minimum qualifications for mortgage loans because of the impact of high interest rates on monthly payments. The program addresses this situation by making a subsidized interest rate program available to the Rojo Caballos worker. This program effectively reduces monthly interest payments.

Assistance to the city of Gillette

Mobil has purchased 1.8 million dollars worth of local improvement district bonds. Revenue from the bonds will be used to extend existing city services, such as streets, sewers, water, and electricity, into developable areas within the present city boundary.

Related community impact mitigation measures

The nine programs described in this section complete the mitigation package. Mobil recognizes that, once newcomers to Gillette are settled in homes, they would have other needs and concerns. The programs described in this section would increase the opportunities within the area for a better quality of living by adding to the educational programs available, adding to library facilities, and increasing the capabilities and strengths of the Powder River Arts Council.

- Local banking accounts.--Accounts would be established by Mobil for local supply purchases and other practical expenditures with selected local banks. This practice would tend to provide additional financing capability in the local sector, thereby providing support for private sector growth and infrastructure development.

- Employee busing program.—Bus service would be provided by Mobil to and from the Rojo Caballos minesite for its employees. Buses with a 40-passenger capacity would be purchased and utilized for this purpose during the life of the mine. When not in demand for employee transportation (weekends), the buses could be used for employee/community recreation trips.

- Video-cassette recorder system.—Mobil would provide the Campbell County library with a VCR/Disc recording system consisting of a video cassette recorder, a video sound camera system, and large-screen television-projection system, a regular color television set, and miscellaneous equipment. Mobil would also donate six films annually. The system would be operated and maintained by the library staff.

- Improvement of local medical services.--Mobil would continue to participate in the doctor recruitment program and other areas to improve medical services. The applicant plans to provide annual donations to help fund the program.

- Powder River Arts Council.--Mobil would continue to support the Powder River Arts Council. This program would be intended to expand the cultural opportunities of Campbell County citizens.

- Campbell County retail sales permit.--Contractors would be requested to obtain a county retail sales permit. Although the permit has no effect on the cost of goods or services, it would provide that the city of Gillette receives an increased share of the sales tax collected by the State.

- Education program for employees.--The workforce of the Rojo Caballos mine would be eligible for company educational benefits. Periodic self-study in-house educational programs would be available to employees, as well as a full tuition reimbursement program for job-related courses taken at approved academic institutions.

- Matching gifts program.--Through the matching gifts program, the Mobil Foundation matches on a two-for-one basis employee donations (above $25) to educational institutions, hospitals, and arts organizations. This increases the gift to the institution and provides a method for added employee involvement in community affairs.

- Socioeconomic impact monitoring program.--The applicant would establish a monitoring program before mine construction. A well-designed monitoring program would ensure that the mitigation strategies are accomplishing their designed purpose.

RESPONSE SET 15

15-1 The recommended stipulations, derived from the U.S. Department of Housing and Urban Development review of the Mobil Oil Rojo Caballos mining and reclamation plan, have been carefully reviewed. The four basic elements dealing with socioeconomic impact mitigation (i.e., construction worker housing, permanent worker relocation assistance, assistance to neighboring municipalities, and general impact mitigation strategies) would clearly be subject to detailed evaluation when and if a specific development plan and schedule are formulated for NOSR 1. For the purposes of this Programmatic EIS, a more general discussion of socioeconomic impacts is believed adequate.

Sierra Club
Rocky Mountain Chapter

"... TO EXPLORE, ENJOY AND PRESERVE THE NATION'S FORESTS, WATERS, WILDLIFE AND WILDERNESS ..."

12 November 1980

Draft Programmatic EIS Comments
Naval Petroleum and Oil Shale Reserves
12th and Pennsylvania Ave., N.W.
Washington,DC 20461

Gentlemen:

The following comments on the Draft Programmatic EIS for the Naval Oil Shale Reserve in Garfield County, Colorado, are made on behalf of the Rocky Mountain Chapter of the Sierra Club. Our organization has 3,000 members in Colorado, many of whom with interests that would be adversely affected by proposed NOSR developments.

It is not easy for us to state our attitudes towards this DEIS precisely. On the one hand, the basic philosophy of approach to this impact analysis of a major Federal synthetic fuel program has some commendable aspects. In the process of examining how X barrels per day of liquid fuel are to be produced, DOE has taken two steps back and has gotten a much broader perspective on the various possible means to that end. Sierra Club people and other environmentalists have been urging such a broad-guaged approach for a long time. The DEIS is particularly valuable because it outlines the extreme impacts and differences in impacts between the different alternatives. It is heartening to see that the results match our expectations, i.e. coal liquafaction has the worst impacts, shale and enhanced oil extraction somewhat less bad, but the best of all by far is conservation. Had the costs to the ultimate consumer been compared for the alternatives, conservation would have appeared in an even more favorable light and the comparisons among the others would have been very illuminating. The lack of such an "economic impact statement" on the consumers' pocketbook is, in our opinion, a substantial flaw that we urge be corrected in the Final EIS. Not only consumers as such, but also in their role as taxpayers, and public officials would benefit from having such comparative information available to them. Moreover, it seems only just, considering the hundreds of millions of dollars, even billions, of public monies which have been or will be used to prop up synfuels operations. 16-1

16-2 On the other hand, we must criticize the DEIS because its aim has evidently been far more ambitious than its means, that is, the analysis is in places sloppy, superficial or wrong. Evidence for this statement is indirect, consisting of the prior assumptions or misstatements discussed below.

16-3 1.) We see problems with the analysis of the biomass alternative. First, it seems more likely to us that during the time frame of possible NOSR development, 50,000 bpdoe would be produced

~~1621 Vine Street~~ Denver, Colorado 80206 303-321-8292
2239 E. Colfax Ave, #206

more economically and practically on the farm using crop residues, not coal, as the distillation fuel. Ethanol produced would displace fuel otherwise purchased by the farmer. We perceive more support on the part of farmers now for a system like this, rather than the centralized facility studied by DOE. Moreover, the technology assumed in the DEIS for ethanol production is swiftly becoming obsolete. Much less energy intensive ways than complete distillation will soon be available; for example, modified corn starch has recently been demonstrated to remove water efficiently from partly distilled feedstock (Fanta, et al, Science, 210, p. 646, 1980; Ladisch et al, Science, 205, p. 898, 1979). Less energy required for distillation means smaller ancillary impacts. However, even if one goes with the conventional technology, projected emissions and inputs are misstated. For example:

a.) Fig 3-4, p. 3-13 compares SO_2 emissions for the technology alternatives. The 16,800 tpy figure for biomass must be the uncontrolled emission rate, whereas the other figures are for controlled emissions. the proper value is 1680 tpy.

16-4 b.) Table 5-10, p. 5-38. The heading of column 2 should be TPD, not BPD. The CO_2 emission figure is incorrect; even if coal were 100% carbon, 4,155 TPD=only 15,200 TPD of CO_2. The figure for uncontrolled SO_2 emission rate seems too low because it assumes only 1.2% sulfur content for eastern coal.

c.) P. C-23. Again, the SO_2 emission figure should be 5.1 TPD not 51 TPD because 90% control has been factored in. See p. 5-37 for this statement.

16-5 d.) P. 3-17, Fig. 3-5. 110,000 acre-feet/year for the biomass operation seems extraordinarily high. Where is all this water going? For cooling? Is the use Consumptive? We would like to see a clearer rationale for this figure.

These four problem statements make biomass seem much more damaging than we believe it to be.

16-6 2.) Emission figure comparisons for proposed NOSR operations and Colony seem way off -- NOSR is consistently lower than Colony by factors of 2-4 -- yet retorting processes and pollution control methods should be similar. For example, while the Colony operation projects (and has received a PSD permit on the basis of) an SO_2 emission level of about 0.11 lb/bbl of shale oil, the DEIS claims in several places (pp 3-13, 5-3, 6-3) that the NOSR operation would achieve about 0.045 lb/bbl, almost 3 times better. It seems probable to us that Colony will use BACT and that even the 0.11 lb/bbl limit will be exceeded when the vicissitudes of equipment operation and recalcitrant sulfur species are taken into consideration. Do the projected emission figures for NOSR mean that a substantial breakthrough in pollution control technology has been made which nobody else knows about? To avoid suspicions that the deck is being stacked in favor of NOSR, these differences must be explained.

16-7 Other questionable figures have to do with economic impacts. On p. 3-28, Fig. 3-10, a 200 bpd operation is projected to cost local governments about $32MM for oil shale developments. State estimates of local needs are several times greater than this. For example, Govenor Lamm has stated that a 400,000 bpd industry would involve capital/services expenditures of about $500MM. Using the $32MM figure above and projecting to 400,000 bpd gives a figure suspiciously close to the present and arguably inadequate, size of the State Oil Shale Trust Fund. Who is right? Has the State had its input on this point?

16-8 Finally, p p. 4-7 states that southern Piceance Basin has a low seismic potential, but if memory serves correctly, Grand Junction and environs experiences fairly frequent, if small, earthquakes.

Other general comments follow:

16-9 1.) P. B-8. Both the domestic inflation rate and world oil price projections seem too low to us, but because these two quantities might change the comparison of alternatives, we request that some sort of sensitivity analysis be done on these and other variables. We suspect that higher inflation rates and oil prices will make conservation look even better. This consideration emphasizes to us once again the importance of calculating the total cost to the consumer of the various alternatives.

16-10 2.) P. 5-67. The statement that rural energy developments do not impact urban areas in the region is dead wrong, for oil shale anyway. Much of the responsibility for the Front Range's socially and environmentally disruptive growth can be laid at the feet of energy developments (up till now metals, oil, gas, coal) in rural areas. This unfortunate trend will be exacerbated by massive oil shale development. A similar statement can be made for quasi-urbanized areas around Grand Junction.

16-11 3.) P. 5-51. Are socio-economic impacts discussed here truly additive between different scenarios of a given technology or various levels of different technologies (the practical case)? It seems to be implied here and elsewhere in the DEIS. We feel that non-linearity or non-additivity of impacts must occur at a certain point, - i.e. the situation simply becomes insufferable for everyone. This point seems to have been reached in certain Wyoming boomtowns and results in enormous personnel turnover.

16-12 4.) P. 5-19. Other EIS's (e.g. the West Central Colorado Coal EIS) have identified such indirect wildlife impacts as increased poaching and harassment of game, loss of, or loss of access to, rich riparian habitat and winter range due to housing developments, and greater competition for game and fish licenses. 16-13 Loss of bottomland and higher tax and inflation rates also strongly impact the present agricultural economy of the shale region.

5.) It is amusing to note, when one considers the potential of saving a mere 50,000-2,000,000 bpd of oil by conservation, that in the past year alone oil consumption has dropped 10% in the U.S., or about the equivalent of 2 million bpd! This, with no government assistance and only at the expense of our slothful and unimaginative auto industry, which richly deserves it!

In summary, the basic thrust of this Draft Programmatic EIS is positive, useful, and potentially illuminating. However, some assumptions used in making comparisons are weak, and enough facts appear to be incorrect (we haven't checked them all!) to make us wonder how many other flaws lurk in the text. We hope that these comments are useful and that the Final EIS will be much improved.

Sincerely,

Kirk Cunningham
Conservation Chairman
Rocky Mountain Chapter

RESPONSE SET 16

16-1 This EIS does not purport to be the only document used in the decision making process. It is but one of a large number of studies and reports prepared regarding the potential development of NOSR 1. Lack of an "economic impact statement" in this EIS does not materially affect the decision making process to which this EIS contributes. Economics is only one of the many factors and was adequately addressed for a Programmatic EIS. To hold that an EIS must contain all the data considered in the decision making process simply does not square with with the CEQ regulations governing EISs, as discussed in Section 2.

16-2 The Sierra Club criticism of the EIS "because its aim has evidently been far more ambitious than its means" would have been much stronger if the converse were perceived. The criticism, though overstated, has some substance, as will be discussed under the specifics referenced.

16-3 Refer to the selection criteria on pages 3-1 and 3-2. Biomass alcohol production from crop residues is still an experimental process, with insufficient data available. The contention that "the technology assumed in the EIS for ethanol production is swiftly becoming obsolete," is strictly a matter of opinion, with which DOE disagrees.

16-4 The SO_2 emissions have been reviewed and were revised based upon the Katzen study and EPA's AP-42, referred to in Appendix B.. The range falls somewhere between 14.6 and 26.4 tons per day. The heading in Column 2, Table 5-10 was corrected. New emissions figures for biomass were calculated and incorporated in the final EIS.

16-5. Revised water usage figures have been incorporated.

16-6 Refer to the response to comment 13-6 for an explanation of the difference between NOSR and Colony and the first portion of the response to comment 3-10 for the source of emissions estimates.

16-7 In responding to this comment, as with the numerous others regarding fiscal impact of the NOSR Development alternative, the point must be made that no one is "right" when engaging in such a speculative endeavor as deriving projections of future revenues and costs of large-scale industrial development. The critical issues to be addressed are the level of detail, comprehensiveness, site-specificity, and sensitivity of the input assumptions which drive any projection of future costs and revenues. The State's Cumulative Impact Task Force is currently engaged in an embitious undertaking to assimilate information and assumptions to derive as reliable and comprehensive cost/revenue projections as are reasonably practicable to address the front-end financing issues confronting the region including the NOSR area. While it is admitted that the projections included in the PEIS have been somewhat simplified, it is suggested that any other such projections generated without the benefit of exhaustive analysis of the factors and assumptions which generate fiscal projections must be found to be similarly deficient. DOE believes that the economic analysis in this EIS is adequate to support the programmatic decisions being made. In addition, all information in this EIS will be reexamined at some future time, when the NOSR 1 development question is revisited, and will be updated where necessary.

16-8 The Naval Oil Shale Reserve No. 1 is an area of low seismic potential. There are no active faults on or near the NOSR property. Only minor damage would be anticipated from distant earthquakes. No restrictions are foreseen in mine placement due to faulting or unstable slopes on the property. Soil creep, rock fall, and rare landslides present the main categories of geologic hazard on NOSR 1.

16-9 Estimates of the future domestic inflation rate and the path of world oil prices vary over a considerable range. Current estimates of the domestic inflation rate, for example, over the next 5 years can be found with a high to low ratio of 3 to 1: it is of course indeterminate.

The uncertainties inherent in estimating the inflation rate and the path of world oil prices were explicitly recognized in the analyses presented in the EIS. It was further stated that the absolute mathematical results of the individual analyses are suspect in terms of accuracy. The technique of using common estimates for these parameters for analyses of each of the alternatives, however, produces results that are useful in relative terms as was indicated in the report.

The benefits to be derived from conducting sensitivity analyses on "those and other parameters" are not apparent.

DOE does not believe that this EIs is the proper venue for conducting a detailed economic and fiscal analysis of oil shale and other liquid fuel production technologies. A sensitivity analysis on "those and other parameters" is beyond the scope of this document.

16-10 The emphasis in the EIS was on the direct impacts on the physical environment. It is recognized, however, that if a large synfuels industry should develop, there would be potential socioeconomic impacts of an indirect nature on cities that are many miles from the oil shale region.

16-11 This comment raises again the need for a level of specificity and detail which is beyond the scope of the analysis contemplated by the PEIS. The illustration of impacts associated with various options under the NOSR Development alternative was intended to convey only a general description of the magnitude of the problems associated with that alternative, based on currently available information. A more exhaustive, quantitative analysis of the specific effects would clearly be required to select from among the specific options under the NOSR Development alternative, if selected.

16-12 Indirect wildlife impacts due to human activity and habitat alteration disturbance are addressed in the second complete paragraph on p. 5-18. Since the area is already heavily hunted, it is not obvious that development will increase competition for game and fish licenses.

16-13 This statement reflects the fundamental structural problem that the speculative value of farm and ranch land far exceeds its agricultural value and that high labor, land, and energy costs will continue to have an unfavorable effect on agricultural production. However, these circumstances are already being experienced in the region and will continue to exist with or without the NOSR project. Any future development of the NOSR project is expected to have only a marginal additional impact on this problem.

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December 3, 1980

Mr. Don Silawski
Naval Petroleum and Oil Shale Reserves
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Washington, D.C. 20461

Dear Mr. Silawski:

The National Wildlife Federation, America's largest private conservation organization, is pleased to comment as follows on the draft environmental impact statement on development policy options for the Naval Oil Shale Reserves.

In general, the Federation sees no need to develop the Naval Reserves at this time. Our position is based on the following beliefs:

17-1(A) I. Private oil shale development on other tracts appears to be more than adequate to achieve any reasonable production goals, thus making development of the NOSR unnecessary;

17-1(B) II. The draft environmental impact statement acknowledges some of the adverse consequences of developing the NOSR, but understates these consequences by failing to describe the cumulative effects of NOSR development together with other reasonably foreseeable development in the area.

17-2 III. The comparison of the benefits and adverse consequences of the different liquid fuels options is inadequate because it fails to account for the presence or absence of key constraints such as local labor, housing, and utility services.

17-3 IV. The net energy analysis in the draft environmental impact statement suffers from important inadequacies.

45th ANNUAL MEETING — MARCH 27-29, 1981 Omni International Hotel Norfolk, Virginia

I. Private Oil Shale Development

A. Generally

17-4

The basic premise of the DEIS is that a "no go" decision is likely if private industry is able to come up with an amount of new oil that would be equivalent to what is expected to be produced from the NOSR. Yet, despite this premise, the DEIS makes no attempt at all to even estimate what the amount of private production is likely to be. Yet the DEIS purports to base the decision regarding development of the NOSR on such an amount. In other words, the equation is lacking a key figure. Before proceeding any further, the drafters of the DEIS must come up with a projected figure for estimated private production which can realistically be expected in the period covered by the President's program for national energy security so that the need for development of the NOSR can be fairly and accurately assessed. Such assessment of the reasonably expected private development should itself be subjected to a public comment period to ensure that the figures are an accurate and fair estimate of the private industry potential.

B. Some Estimates of Amount of Private Development

Source: Cameron Synthetic Fuels Report; Department of Interior

PROJECT	LOCATION	PRODUCTION TARGET AND DATE	STATUS SUMMARY
Rio Blanco Oil Shale (Gulf, Standard of IN)	Fed. Lease C-a (Rio Blanco, CO)	76,000 BBL/DAY (1987)	
Cathedral Bluffs Oil Shale (Occidental, Tenneco)	Fed. Lease C-b (Rio Blanco, CO)	57,000 BBL/DAY (1987) Cathedral Bluffs has apparently increased this estimate to 117,000 BBL/DAY as evidenced by the pleadings currently before the Colorado Air Quality Control Commission	
White River Shale Proj. (Sundeco, Phillips, Sohio)	Fed. Lease Tracts U-a and U-b (Utah)	100,000 BBL/DAY (1990)	

B. continued

PROJECT	LOCATION	PRODUCTION TARGET AND DATE	STATUS SUMMARY
Colony Developmnet (Exxon)	Colony Dow West (Colorado)	46,000 BBL/DAY (1985)	Inactive pending improved economic conditions
Long Ridge Project (union Oil of CA)	Union Property (Colorado)	9,000 BBL/DAY prototype 50,000 BBL/DAY if they go to production	Inactive pending improved economic conditions
Sand Wash Project (Tosco)	State Leased land (Utah)	50,000 BBL/DAY (1990)	Site evaluation and feasibility studies underway. Lease terms require $8 million investment by 1985.
	TOTAL:	379,000 BBL/DAY	

As is shown by the above total, approximately 380,000 BBL/DAY is projected by 1990 from private industry projects already underway. This figure suggests that the private sector is projecting almost enough oil development to meet the 400,000 BPD decrease in imports sought by the President by 1990. The above projects are just a sample of projected levels. EPA has recently intimated that production may be as high as 520,000 BPD by 1990. And Exxon has predicted an 8 million BPD production level by 2010. Surely this indicates that the premise of the need to use the Naval Oil Shale Reserves to meet the liquid fuel goals must be reassessed!

II. Cumulative Environmental Impacts

17-5 Contrary to the premise in the DEIS, we feel that a detailed environmental analysis is required at the programmatic stage of decision making. The purpose of the DEIS is to provide relevant information on the environmental effects of a decision to develop additional federal land, specifically Naval Oil Shale Reserve No. 1 (NOSR 1), for shale oil production. This decision must be an informed one based on an in depth evaluation of the individual and cumulative impacts. Now is the time to consider those effects, not after a decision is made to proceed with additional development. It is not enough to identify problem areas without analyzing them in detail (DEIS, p. 5-1).

While individual impacts of NOSR 1 and the alternatives are at least discussed in a general (although completely inadequate) fashion, cumulative effects are scarcely given lip service. For example: "The cumulative effects of regional energy development could have a significant impact on air quality in the region" (DEIS, p. 5-3). Is this information at all helpful in making a decision as to whether or not to develop a multi-billion dollar facility?!!

17-6 Cumulative effects are not even mentioned in two other critical areas: water and socio-economics. New water consumption for NOSR 1 is estimated to be from 4.6 MGPD to 15.0 MGPD which would be diverted from agricultural use (DEIS, p. 5-4). This effect on farming may be small when compared with municipal growth as the DEIS observes. However, when superimposed on the water usage from the other proposed oil shale and mining operations in the area, the effect on agriculture water rights could be very substantial. These effects must be evaluated.

17-7 Again, individual impacts of NOSR 1 on socio-economics are at least discussed, but nothing whatsoever is mentioned about the cumulative effects of all the shale oil operations in the region (or perhaps even the beneficial effects from some of the alternatives in other areas). The DEIS recognizes the considerable stress that a major facility siting will impose on a rural area. It should further recognize, and discuss in detail, the compound stress that a number of such facilities will have on the region. If one facility will exceed the ability of an area to assimilate thousands of workers, what will several facilities do? How are schools, police and fire protection and a host of other services going to be provided by concurrent development of NOSR 1 and the other already planned projects? It may be that the alternatives to NOSR 1 may be beneficial to areas of high unemployment (unlike western Colorado). Surely these questions are relevant to the decision makers at the programmatic level. They must be answered before a decision is made to develop NOSR 1.

III. Comparison of NOSR to Other Liquid Fuels Options

One fundamental fact must be kept in mind in analyzing the various potential sources of liquid fuels: many of these sources can be produced in a variety of geographic locations, while oil shale from the NOSR will of necessity be produced in a small, well-defined geographic area.

This fact is of great significance in terms of the impacts of development. If alcohol fuels, or even OCS oil, were to be selected, development could occur at a variety of sites. In the case of oil shale, development--both on and off the NOSR--is necessarily limited to a relatively small region of Colorado, Utah and Wyoming, where the only known significant high-grade shale reserves exist.

There is even some possiblity of channeling development of some of these other liquid fuels to areas where impacts which would otherwise be detrimental would be beneficial. For example, the pool of unemployed labor in western Colorado and eastern Utah is relatively small. Any significant development in this area would require that large numbers of workers move into the area. This would result in a number of significant adverse impacts:

1. People would be uprooted from stable communities elsewhere, where they may have family, social, and other ties, and where they now live by choice, and moved to a new area.

2. The receiving area lacks adequate housing, schools, public safety services, gas and electric utilities, roads, and many other forms of infrastructure, all of which would have to be built at very substantial cost to society.

3. During the transition period while infrastructure is being developed, the incoming workers will be exposed to unstable, crowded, transient conditions, high costs for necessities, and other conditions hardly conducive to the establishment of stable, healthy communities,

On the other hand, there are clearly existing communities without adequate employment, but with housing and other community services already intact, which could be intentionally targeted as sites for energy projects. Rather than creating problems, such projects could be a real benefit to areas needing the employment base.

There are a number of other ways in which this principle is demonstrated:

A. Availibility of Electrical Service

Oil shale projects, with associated development, will place a severe strain on electrical generating capacity in western Colorado and eastern Utah.

Energy requirements for oil shale development may be quite significant. As we stated in more detail in our written and oral comments on the scoping of this draft environmental impact statement, there is a critical and growing shortage of electrical generating capacity in Colorado.

17-8 The effect of this capacity shortage is clear. At a time when the cost of constructing new generating capacity of any kind is almost prohibitive, increases in electrical demand will force area utilities to invest enormous sums in new plants, with highly adverse consequences to utility ratepayers.

The adverse consequences will not be limited to local utilities and ratepayers: it is an immense waste of our society's resources to build new generating plants in one region, while generating plants in other regions are idle or under-utilized.

At present, excess utility capacity is near 40% on a nationwide basis. Indeed, some utilities' plants are suffering excessive physical damage as units designed for base load operation are being forced to operate in a cycling mode, subjecting components to thermal stresses for which they were not designed.

It is patently unreasonable to treat two alternatives the same when one requires construction of major power generation and transmission facilities and the other does not. The fact that local utilities and ratepayers, rather than federal energy agencies, will be footing the bill for costly construction programs does not provide an excuse for failing to analyze this fundamental problem.

17-9 In the past it has been suggested that increased electric load attributable to oil shale facilities can be met by generating electricity from off-gas from shale facilites. This has provided a neat rationale for failure to analyze the critical electrical supply problems posed by oil shale development on the NOSR and elsewhere. However, this response is utterly inadequate:

(a) because of technical problems, economics, or for other reasons, private shale developers appear to be contracting for power from utilities rather than using off-gas generation; and

(b) off-gas generation does not solve the problem of providing power for residential, commercial, and industrial growth induced by shale development.

A number of the alternatives to NOSR development have the potential of being located in areas with surplus power. NOSR development would require increased development of electrical supply, at enormous cost. Hence, the alternatives are not fairly treated without analysis of this problem.

B. Natural Gas Supplies

A similar situation obtains with respect to natural gas--the primary source of heat for buildings in this area.

Natural gas has only recently been in very short supply. Colorado's largest utility has had a moratorium on new gas hookups in response to this shortage.

Further, the rates paid by gas customers reflect an average price paid by utilities to their suppliers. Utilities obtain gas under numerous contracts with pipeline companies. Older contracts generally make gas available at relatively low prices; 17-10 newer contracts are at much higher prices.

The effect, then, of growth induced by shale development, including development of the NOSR, will be to exhaust gas available under older, low-cost contracts more rapidly, requiring more new contracts at higher prices. The net result will be dramatic increases in gas cost to customers, and increased strain on supply, as well as the capacity of transmission and distribution facilities.

Again, the balance should include these extra costs attributable to NOSR development, contrasted against other types of energy development which may be targeted to areas with adequate gas supplies or other energy sources.

C. Water Availability

NOSR development in the arid Colorado Basin will require (i) transfer of water from existing users, or (ii) construction of new water projects, or (iii) both, in some combination. This may be contrasted to other energy sources, which may be developed in areas with existing adequate water supplies.

D. Summary

In short, the draft environmental impact statement fails to adequately balance the costs and benefits of the various alternatives. Note that we are not here suggesting that all values can be quantified and subjected to dollar-for-dollar comparison. We are suggesting that an alternative--perhaps alcohol fuels--which can be sited flexibly to take advantage of resources which are in surplus--has many advantages over NOSR development which are not adequately treated. A comparison might be as follows:

17-11

NOSR DEVELOPMENT	ALTERNATIVE
1. Labor. Labor supply in the local area is inadequate. Workers must be induced to relocate into the project area.	1. Labor. Project can be built in an area with high unemployment, providing needed jobs without requiring relocation.
2. Housing. Local housing is unavailable in adequate supply. Workers will be forced to pay high prices for temporary housing, which will be constructed at substantial costs.	2. Housing. Housing supplies should be adequate, or nearly so, since little in-migration will occur.
3. Public services. Nearly all public services--roads, schools, sewers, water supplies, public safety services--are inadequate, and will have to be improved and expanded at enormous expense.	3. Public services. Existing services should be strained very little, since comparatively minor population increase is to be expected.
4. Communities. Unstable "boom towns" created, where residents lack community ties, a high degree of transience, and associated problems.	4. Communities. Existing social relationships are largely preserved.
5. Utilities. New electrical generating capacity needed,	5. Utilities. Added demand may actually benefit utilities with

5. Utilities cont'd. which can only be constructed at enormous expense causing rapid rate increases. Natural gas supplies will be tight and rates will increase. Added generating capacity will have important adverse environmental impacts.	5. Utilities cont'd. underutilized capacity. Since no new plants would be needed, there would be little additional adverse environmental impact.
6. Water. Prime agricultural land will be taken out of production and/or new water projects will be needed at enormous cost, with significant adverse environmental impacts.	6. Water. Water supplies from existing sources may be adequate--or nearly adequate--for project needs.
7. Cumulative effects. All oil shale production facilities will all necessarily be built in a confined geographic region. Cumulative impacts are unavoidable.	7. Cumulative effects, Production facilities may be dispersed around the country, avoiding excessive impact in any single locality.

The above list could be added to easily. Our point is simply this: the objective of this environmental impact statement should be to analyze pragmatically and fairly, the available alternatives. By failing to treat the issues identified above, it fails utterly in its principal purpose.

Frankly, the fact that we have raised these issues extensively in the scoping of this draft environmental impact statement, with no noticeable effect on the resulting document, leaves us with serious questions as to DOE's intentions.

Imagine a large industrial enterprise considering the construction of a new facility. The committee charged with identifying a site comes in with various alternatives, including Sites A and B. They find little to choose from between these alternatives.

Management asks whether there is an adequate labor supply at both sites. The committee responds by saying "there is at site A, but not at site B. We didn't go into that in detail because we didn't think it was important."

They are asked whether there is adequate electrical supply at the sites, and respond that they don't know.

Management inquires whether there are adequate local water supplies, and is told "no, but we hope that someone will build a dam."

"Is there adequate housing for personnel?" is the next question. The answer: "No. And by the way, nine other major plants are planning to locate in the vicinity. But we didn't discuss that in our report."

Clearly, such a committee would be told to start again, and to finish its work by addressing these crucial questions, which would be at the top of the list of things management would want to know.

DOE, charged with the public trust, and responsibility for a broad range of environmental consequences, has responsibilities far in excess of the responsibilities of such a hypothetical corporate manager. Yet the analysis presented to guide DOE management is much less adequate than the analysis used by business managers in the most routine plant siting decisions.

DOE attempts to skirt this issue, and, indeed, the entire issue of the merits or demerits of particular liquid fuel sources by reverting to the non-policy of saying "we have to develop all of everything we can."

This statement means nothing. The federal government, like any enterprise, has limited resources. A commitment of a part of those resources to one technology makes less available for other technologies.

This is simply the basic economic notion of "opportunity cost." If the NOSR is developed, commitment of resources to that development will necessarily mean that some other things can't be done. If the avowed purposes of this environmental impact statement include serving as "input" for the decision as to "whether to promote development of oil shale on federal land" (p. 1-1), then the questions raised in these comments can hardly be avoided.

IV. Efficiency of Process

17-12 The discussion of process efficiency in this document is simply unacceptable. This issue is central to a comparison of alternatives yet it is disposed of (and that is the best we can say of its treatment here) in fifteen lines and one figure. Reference is made to Appendix C where, the reader is told, will be found the basis for the scanty data presented. Nothing in Appendix C is the least bit enlightening in respect to how the determination of process efficiency was made.

This section simply must be redone if this document is to be considered a credible and defensible analysis of alternatives.

We have some specific comments:

17-13 1) A comprehensive net energy analysis for all alternatives must be done. This should include all energy costs (e.g. we believe that the energy costs associated with moving workers, their families and others to new towns in the oil shale areas will be significant).

17-14 2) The Conservation alternative should be reanalyzed after it has been reformulated to include a more comprehensive plan than just savings due to weight reduction of vehicles. This assumption is patently absurd.

We believe that oil shale development will not produce a large amount of energy, or liquid fuels, on a net basis, when carefully considered. This is so because history shows us that the projected price of shale oil has been closely tied to --and always slightly in excess of--imported oil prices.

Thank you for the opportunity to comment on this draft environmental impact statement.

Sincerely,

Luke J. Danielson, Counsel   Henry G. Swain, Legal Intern

LJD/HGS:emv

RESPONSE SET 17

17-1A See response to comment 17-4.

17-1B See responses to comments 17-5, 6, and 7.

17-2 The precise manpower, utility, and other input factor requirements that would be associated with development of NOSR 1 cannot be known until specific development terms and plans of the NOSR property are identified. The most prominant variable is the one that will determine presence of key factor input constraints most subject to direct DOE policy initiatives, namely the overall timing or program schedule for construction and operation. The time schedule for development of NOSR 1 in combination with other potential industry development in the same general area will be the major determinant of whether a labor surplus or shortfall will prevail and whether cooperative housing ventures will be required.

17-3 See response 3-8 and Appendix C.

17-4 The decision to develop NOSR will be made by the administration based upon all criteria it deems important. The EIS, one input to that decision process, does not suggest that the rate of development of private oil shale is the sole criterion. The table of shale projects, provided in comment 17-4, lists goals and does not reflect actual activities. Exxon did not predict 8 million BPD by 2010, but merely suggested it would be possible, given a whole host of conditions occurring. As was stated in the response to comment 2-7, the draft EIS was unfortunately somewhat vague on the purpose of the proposal. We believe a revised Section 2 clarifies this point.

17-5 Analysis of cumulative air and water quality impacts related to development in the oil shale region is beyond the scope and purpose of this programmatic EIS. Also, see the response to comment 2-8.

17-6 See above 17-5 and below 17-7.

17-7 A general analysis of cumulative socioeconomic impacts has been added to the Final EIS. However, detailed cumulative impact analyses of all oil shale operations in the region are clearly beyond the scope and purpose of this PEIS, as explained in the response to comment 2-8.

As to the final concern expressed in this comment, that of consideration of alternatives to the NOSR project in terms of unemployment existing in other areas vis-a-vis western Colorado, it should be noted that any analysis of a factor of such a transitory and speculative nature as periodic unemployment is clearly beyond the scope of this analysis. To even attempt such an exercise would involve the projection of national and international economic conditions expected to prevail with respect to the demand and supply of products and services currently produced and likely to be produced in the future in each of the regions of study. This is to say that a simple analysis of current unemployment rates in each of the areas under study would not yield credible results for comparisons of alternatives which would take years to develop.

17-8 The commenter raises a good point concerning differential regional electrical generating capacities, one that should be taken into account in siting studies for major facilities. However, consideration of this factor is beyond the scope of the NOSR programmatic level EIS at this time, as discussed in the response to comment 2-8.

17-9 See response 17-8 above.

17-10 Refer to the response to comment 2-8.

17-11 The comment states that the EIS "Fails to adequately balance" the various alternatives, and provides an example of such a balance in a table itemizing seven factors for NOSR development versus alcohol fuels.

The factors listed, largely second-order socioeconomic factors, are important, as are numerous other factors, depending on the interests of the commenter. The EIS does make a quantitative comparison of all the primary impact factors, but without adding a judgmental value that must be reserved for the policy makers. DOE does not believe that additional details are needed for the final EIS, at this time.

17-12 Data sources are referenced and only straightforward mathematical analyses are required to duplicate the calculations made. The constituent components of each energy calculation are included in this final EIS. Refer to the response to comment 3-8 for a discussion of net energy analysis.

17-13 Refer to response to comment 3-8.

17-14 Refer to the selection criteria on pages 3-1 and 3-2 and the response to comment 2-4. This EIS does not have as its purpose the development of a comprehensive conservation plan. The belief "that oil shale development will not produce a large amount of energy, or liquid fuels on a net basis, when carefully considered" is at variance with the detailed net energy analysis in Appendix C. Also, see response to comment 5-1G.

FRIENDS OF THE EARTH

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Dear Mr. Silawsky:

The holiday schedule and our own work load made it difficult to mail the attached comments in time to reach Washington by the Friday, 28 November deadline.

In fact, we called your office Friday without obtaining any answer several times.

Thus, we hope that you will accept these comments hand-delivered early Monday morning, since I will be in DC that day on other business. Attached is also a copy of the mailgram I sent Friday after not succeeding in reaching you by phone.

Sincerely,

Kevin Markey

Kevin Markey
Colorado Representative

Attachment
cc: ASEV Ruth Clusen
Colorado Department of Natural Resources

Committed to the preservation, restoration, and rational use of the Earth.

FRIENDS OF THE EARTH
COLORADO OFFICE
2239 EAST COLFAX AVENUE ROOM 209
DENVER, COLORADO 80206
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28 November 1980

COMMENTS ON THE DRAFT PROGRAMMATIC ENVIRONMENTAL IMPACT STATEMENT ON THE DEVELOPMENT POLICY OPTIONS FOR THE NAVAL OIL SHALE RESERVES, COLORADO.

General Comments

18-1

The environmental impact statement states that the Department of Energy (DOE) will propose Naval Oil Shale Reserves (NOSR) development if there is "an absence of meaningful private oil shale development during the next year to 18 months." (1-3) What does this mean? DOE must define the circumstances, conditions, and criteria by which private shale industry success is judged. Moreover, it is crucial that DOE establish such criteria, publicly, before it must make its decision. Such criteria should be part of the proposed action. If not, it will be too easy for the agency to change its criteria internally depending on what circumstances demand.

For example, the Department of the Interior consistently claimed that its prototype oil shale leasing program was a big success. That is, until it wished to justify additional prototype leasing. Suddenly, judged against an impossible goal (the testing of all major technologies within the program), DOI pronounced the prototype program a "qualified success" -- though, it was obvious by their intent that they considered it a dismal failure.

We would suggest that there is already meaningful development leading to production of more than 400,000 barrels per day. Construction is proceeding on four projects. Permit applications are moving forward on several more. With lands already leased or those under private ownership it will be possible to produce nearly 600,000 BPD by 1990 or 1992.

Shale development has already attracted several federal favors:

* A 20% business investment tax credit.
* The $3 per barrel production tax credit (equivalent of a price guarantee if world prices fall under a criteria price).
* The incentives of the Energy Security Act.
* The existing and proposed expanded prototype leasing program.
* Several favorable decisions regarding environmental regulation.

Does it need more, even on a contingency basis? We think not. If industry fails with all this assistance, it is time to bite the bullet and look for a more promising solution to our energy problems. We need not bankrupt the public treasury and resources for a loser which cannot succeed with all these favors.

18-2

Although we believe that the answers are obvious, we believe that it might be helpful for DOE to assess the likelihood of achieving various production goals without NOSR development and without further government action (other than the implementation of recently approved programs). One DOE assessment submitted to DOI during Interior's consideration of new leasing indicated that 400,000 BPD could be achieved by 1990 without new leasing. That assessment was based on very conservative assumptions and came before announcements by Cathedral Bluffs, Chevron, and Union of new or increased production plans.

It seems that everytime DOE (or the industry) wants some new favor, the Department raises the spector that synfuels production will be impossible without the new favor -- be it new leasing, off-tract disposal, weakening the Clean Air Act, establishing an Energy Mobilization Board, etc. It is time for DOE to come out of the closet and subject its analysis to public scrutiny. The need for NOSR development must be analyzed. The success of recent initiatives must be honestly evaluated. The no-action alternative must be assessed as to whether it can achieve national policy goals. This is required, in fact, by NRDC v. Hughes. Thus, DOE must include in the EIS an assessment of how much production can be achieved without NOSR or other action.

18-3 Moreover, this analysis and any proposed criteria for proceeding with NOSR development should be subject to comment prior to issuance of the final EIS. Therefore, we suggest publication and circulation of a draft supplement for comments on these additions prior to inclusion in preparation of a final statement.

18-4 In further discussion of the purpose of the NOSR program (chapter 2), DOE reveals a strong bias toward proceeding with oil shale development in comparison with the alternative energy options. It states that the no-action alternative is likely if two conditions are fulfilled. First, private oil shale operations must be proceeding satisfactorily. Second, one or more of the energy alternatives must be both possible and preferable. This implies that DOE will do everything necessary to achieve oil shale goals, including establish a contingency leasing program. Second, it implies that existing programs for the energy alternatives will be sufficient. No contingency plans for conservation implementation, for example, are proposed. We suggest eliminating the second condition.

Technical Analysis

Methodology

The EIS makes an admirable attempt to make quantitative comparisons among technologies. However, there are several methodological flaws.

18-5 First, in drawing together the case study which represents development on NOSR, the investigators have actually constructed a multi-technology option with is broadly representative of some oil shale technologies. In making assumptions, for example, about air pollution impacts, the emissions of several technologies were used in the NOSR analysis. (As indicated below, even some of these analyses, even though presumably "representative" of industry norms, are actually in error and may underestimate NOSR impacts.) However, the EIS then compares this NOSR analysis with site-specific plans which are not representative of their industries.

DOE states that "environmental emissions neither excessively large nor small compared with other technologies that could represent the alternative" were employed in the choice of energy alternatives analyzed by the EIS. However, an Illinois ethanol plant which uses 6.1% S coal is probably the worst biomass alternative; the SRC-II technology probably results in the highest product toxicity among coal synthetics; and Kern County enhanced oil recovery using steam injection probably has the highest water use and air pollution potential.

18-6 Nowhere are these methodological problems more evident than in the comparison of air emissions. (See details, below.)

18-7 Also, there may be problems in comparing the oil shale proposal to SRC-II, which has significantly different products.

Details

18-8 3-25: DOE assumes that there will be several economies in proceeding to 200,000 BPD, especially in the area of socio-economic impacts, because workers will remain on the job four times longer, instead of building the capacity all at once. However, if the 200,000 BPD must be constructed quickly to make up an expected shortfall in private shale oil production in 1990 or 1992, DOE must quadruple its construction force. This will more than quadruple the socio-economic impacts. Several analysts have pointed out that more rapid development will result in exponentially greater social impacts. Even with the construction spread out, the increase in production and population will probably be more serious than DOE estimates. Moreover, even if on a per-barrel basis impacts are reduced, there are certain thresholds which may be reached if the region overextends itself.

18-9 1-8: DOE suggests that there will be no environmental advantages with GOCO, utility, joint venture or other modes of development with high federal involvement. We disagree. Theoretically, environmental control or information generation could be higher with greater federal involvement, if such involvement proceeds with adequate public participation and scrutiny and if it is done without the cost-cutting effects of competitive, strictly private development. Federal development with careful quality control could set high standards for industry-wide environmental control. Of course, this is theoretical. If the record of DOE coverups or footdragging which has characterized the SRC tests or the Paraho Anvil Points site continue, there will be only disadvantages to federal involvement. Moreover, with a well designed private involvement program and close public scrutiny, these same theoretical advantages can accrue to a program which does not have maximum federal involvement in direct management of a project.

18-10 3-11: There is no basis in fact for the EIS's judgments that NOSR air emissions will be lower than those on "other" oil shale lands. At first glance, the EIS analysis may be an artifact of a faulty methodology. In particular, the EIS compares the emissions of a single facility to represent the entire industry (Colony) with estimates for a single facility which were derived from estimates for the entire industry (see note (3) page C-3). However, further analysis of the NOSR EIS indicates that the NOSR case underestimates SO_2 emissions and that the "Other Oil Shale" case (Colony) overestimates actual particulate matter (PM) and NOx emissions.

	Emissions (lb per barrel of oil produced)		
	SO_2	PM	NOx
NOSR (EIS appendix C)	0.04	0.12	0.44
Other Oil Shale (")	0.14	0.40	0.90
Industry range (OTA)	0.13-0.72	0.09-0.18	0.26-1.68
Colony (OTA)	0.13	0.12	0.93

OTA = An Assessment of Oil Shale Technologies, Office of Technology Assessment, 1980.

More recent analyses indicate that SO_2 emissions may reach as low as 0.10 lb/barrel (Colony or Lurgi). However, it is unlikely that Paraho or the directly heated vertical combustion kiln assumed by DOE in the NOSR analysis will reach that level of sulfur dioxide control. The recent Anvil Points EIS assumed very high sulfur control, for example, but did not take into account the effects of organic sulfur emissions on sulfur cleanup efficiency. This was a major issue in the recent hearings before the Colorado Air Quality Control Commission. The DOE should be careful not to underestimate SO_2 emissions.

18-11 3-22: Similarly, there is no basis for a difference in socio-economic impacts between shale technologies. Since no technology has actually been chosen for NOSR development, and since DOE chose to limit "other" oil shale to the Colony plant design, one cannot conclude any differences.

18-12 3-6: In deciding which technology should "represent" "Other" oil shale, DOE chooses Colony by a process of elimination. Lurgi, Occidental MIS, Superior, Union, and Paraho are not chosen because of small scale tests, inadequacy of data, or because Colony had generated more data. Different criteria are used in the choice of technology for the NOSR case study, resulting in the choice of Paraho retorting plus TOSCO for the fines.

This variable standard does not result in an accurate comparison of NOSR and other shale resources. Only the characteristics of the resource should dictate the choice of the technology. The technologies chosen for the NOSR case study could be applied anywhere. The only differences would result from differences in environmental setting or the geochemistry of the shale. Thus, central Piceance Basin siting might increase sulfur emissions because of higher S content in the shale feedstock. (This might not occur, depending on the retorting technology.) However, south rim locations such as NOSR would be most sensitive to cumulative impacts of surrounding or neighboring facilities. (Union, Colony, Mobil, Chevron)

Even though DOE rejects all the other technologies because of inadequate environmental data, the industry has not. Various developers are planning modular or full-sized commercial applications using Union B, Lurgi, Oxy MIS, and Paraho technologies.

18-13 3-16: Even though there is no generally accepted Flattops PSD analysis, it is general knowledge that 400,000 BPD is considered to be the maximum safe production level assuming 0.16 lb/barrel emissions for sulfur dioxide by EPA for planning purposes.

18-14 3-16: Non-attainment for TSP (PM) is applicable today only in Mesa County. EPA reinterpretation of data and law means that Rio Blanco and Garfield Counties are PSD for particulate matter.

18-15 3-21: Even though the cumulative health and safety risks represented in fugure 3-6 are probably correct, the discussion in the text which posits a "light" safety risk for coal and oil shale liquids is probably incorrect. Mining hazards are a problem with both, probably more severe with coal. However, even oil shale has problems with gassy mines, hydrogen sulfide gas, and poor rock stability, especially in the center of the basin.

18-16 3-23: The socio-economic impacts of biomass option may not be as "significant" as indicated here. First, the development of a concentrated 50,000 barrel per day equivalent ethanol operation in a single location is unlikely. More likely will be dispersed siting of many small plants and their gradual construction. Second, many small plants are likely to be constructed on farms, rather than at centralized locations. Third, the region chosen by the EIS analysis, as well as other likely ethanol plant locations, has a much higher population density and many larger communities than does the oil shale region. With oil shale and other fossil synthetic fuels there is no choice but centralized, concentrated development and most sites are planned in low-population density locations. Moreover, the mid-west is suffering greater unemployment than the already booming energy regions of Colorado and other western energy centers. Thus, biomass production in Illinois, together with dipersed siting, may have beneficial rather than negative effects. For the same reason, the expenditure levels assumed for biomass may be higher than necessary.

18-17 3-23: The text seems to indicate that well-planned "new towns" such as Battlement will lessen the significance of socio-economic impacts. This is incorrect. Such "new towns" are only a symptom of the seriousness of the problems. "Adequate prior planning and preparation" will not make impacts insignificant. It will only help make them more manageable, perhaps. For example, no one knows whether Battlement will work.

18-18 3-28: The revenue/expenditure balance for NOSR is misleading. Total plant-life revenue is not the problem. The lack of lead revenues with which to prepare for impacts is the problem.

18-19 4-10: There is no information on the socio-economic environment for central Illinois.

18-20 5-2: Mercury and possibly arsenic may be significant non-criteria pollutants.

18-21 5-3: DOE should not wait for the site=specific EISs to do a cumulative air quality analysis. Concern is great concerning the cumulative air quality impacts of NOSR, Union, Chevron, Colony, and possibly Mobil.

5 general: Most of the description of oil shale's problems are quite accurate. Why we continue to pursue this option when we know the risks is beyond us.

18-22 5-9: The conservation alternative only assumes automobile efficiency improvements to reduce petroleum consumption. However, reductions in VMT (vehicle miles traveled) may be even more effective in reducing emissions.

3-13, 5-37, Appendix C, etc: The EIS contains an unfair comparison of shale and biomass SO_2 emissions. Admittedly, if extremely small ethanol plants are dispersed in many locations and use high-sulfur coal, we will have severe air quality problems. However, moderate scale biomass plants will involve emissions cleanup. Sulfur control efficiency need not be as skewed as DOE indicates.

18-23 Uncontrolled oil shale emissions (50,000 BPD) will be 240-384 tons per day SO_2 (OTA). Uncontrolled biomass emissions assumed by DOE will be 510 tpd. This assumes 6.1% sulfur coal. Lower sulfur coal and crop residues are available which can significantly reduce uncontrolled emissions. If equal control efficiencies are applied, biomass and oil shale will have much closer emission rates. 0.04 lb SO_2 per barrel (oil shale) represents about 99.9% efficiency. However, DOE assumed only 90% efficiency for sulfur control with biomass. While some shale technologies can today achieve 99.6% S removal, some companies contend that they cannot exceed 95% removal. This assumes the use of flue gas desulfurization.

With high sulfur coal and FGD, 95% efficiency can also be reached. Thus, biomass may have a comparable emission rate to at least MIS oil shale technologies.

18-24 5-37: The 5.1 TPD SO_2 is not consistent with other figures (C-23, 3-13, or table 5-10). Which is right?

5-38: The discussion of water consumption here and in chapter 3 and Appendix C is confused and possibly inaccurate. The important variable is water consumption -- not water delivery capacity. The later is important for sizing well delivery or water storage capacity, but the critical variable in computing total water availability is net consumption. If water is removed from a stream, but most is returned for reuse, other users are not affected except by quality degradations.

18-25 All the figures used in the analysis refer to water delivery capacity, not net water consumption. This should be changed.

Particularly bothersome is the large water requirements for biomass. However, we believe that most of this is return flow. Of the 109 MM GPD input for ethanol production, the EIS indicates that output of 15.4 MM GPD requires treatment. However, much more output will not require treatment (e.g., cooler blowdown or cooling water). There is no complete information on water balance. This should be provided. (We searched several documents unsuccessfully to find such an analysis. Only a small amount of water is used for making the mash. It is this that is lost, plus a small amount of cooling water makeup.)

18-26 C-3: The water (net) consumption for the NOSR case study amounts to less than 1 gallon of water per gallon of shale oil produced. This is not consistent with other analysis, which indicates a minimum ratio of 2 barrels per barrel produced (OTA). Also, the choice of one of the least water intensive technologies for NOSR biases the analysis against the choice of one of the most water intensive technologies for "other oil shale."

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4-0245108333002 11/28/80 ICS IPMBNGZ CSP DVRB
1 3038318759 MGM TDBN DENVER CO 11-28 0238P EST

KEVIN MARKEY, COLORADO REPRESENTATIVE
FRIENDS OF THE EARTH
2239 EAST COLFAX
DENVER CO 80206

THIS MAILGRAM IS A CONFIRMATION COPY OF THE FOLLOWING MESSAGE:

3038318759 MGM TDBN DENVER CO 62 11-28 0238P EST
ZIP
DONALD SILAWSKY, ENVIR PROJ MAN US DEPT OF
ENERGY NAVAL PETRO & OIL SHALE RES
MAIL STOP 3344
12 AND PENNSYLVANIA AVE NORTHWEST
WASHINGTON DC 20461

REQUEST PERMISSION FOR EXTENSION FOR NOSR EIS COMMENTS UNTIL MONDAY MORNING DECEMBER 1. WILL HAND DELIVER. APPARENTLY OFFICE IS CLOSED ON FRIDAY.

KEVIN MARKEY, COLORADO REPRESENTATIVE
FRIENDS OF THE EARTH
2239 EAST COLFAX
DENVER CO 80206

14:39 EST

MGMCOMP MGM

TO REPLY BY MAILGRAM. SEE REVERSE SIDE FOR WESTERN UNION'S TOLL - FREE PHONE NUMBERS

RESPONSE SET 18

18-1 Refer to the response to comments 3-5 and 17-4.

18-2 See response to comment 17-4.

18-3 DOE does not believe that there are substantial changes in the proposed action that are relevant to environmental concerns not addressed in the draft EIS, or that there are significant new circumstances or information relevant to environmental concerns which would require a supplement to the draft EIS. If such information is developed at some later reexamination of the NOSR 1 project, then a draft and final supplement to this EIS will be prepared, pursuant to the CEQ NEPA regulations.

18-4 Refer to the response to comment 2-7.

18-5 In the description of the NOSR reference plant on pages B-1 and B-2, specific processes, not general industry representation, were used. Refer to the response to comment 3-10 for a discussion of Colony's selection. Coal used for the biomass option was Illinois No. 6, which is 3.34% sulfur. We have no data to support the claim that SRC II results in the highest toxicity among coal synthetics. Data available for EOR projects in that region of California do not support the contention that it has the highest water use and air pollution potential.

18-6 Assumptions of problems in the methodology for air emission comparisons have no basis in fact. (See response to comment 18-10.)

18-7 Refer to the response to comment 10-4.

18-8 The simultaneous construction of four 50,000 bbl/d facilities at NOSR 1 is not a feasible option from the standpoint of socioeconomic impact considerations. DOE is acutely aware of the cumulative socioeconomic impacts in the NOSR region currently emerging from the Union, Colony, and C-b oil shale ventures.

18-9 There should be no differences in environmental impact due to selection of a development option because DOE will have an important role in the project whether it is leased, developed as GOCO, or developed by other means. Similar environmental stipulations and requirements will be applied to any project, regardless of the development policy option selected.

18-10 The air emissions estimated for NOSR are for a specific plant using a specific mix of processes. The emissions estimates were supplied by the developers of the processes. Industry averages were not used. (See description of the NOSR plant on pages B-1 and B-2.) Refer to the selection criteria on pages 3-1 and 3-2 for an explanation of Colony's selection.

18-11 The variations in socioeconomic impacts occasioned by the development of different technologies under a NOSR 1 development option would likely be minimal. It is conceivable that larger work forces could be required for in situ technologies than those required for surface technologies; however, there are other features of any given development configuration that would have far more significant influence on the magnitude and adversity of NOSR 1-based socioeconomic impacts. It is generally agreed that the severity of socioeconomic impacts associated with oil shale development derives primarily from the level of employment involved: the larger the work force of a given development the more discernible is the social and economic effect on the local environment. Thus the absence or inclusion of labor-intensive ancillary facilities (at least with regard to construction manpower) such as upgrading or hydrotreating facilities, unique water diversion or storage structures, pipelines, fixed rail transportation systems, community development or work camp residential accommodations, off site fabrication and staging facilities, in short, any of these variable features of a given oil shale project can substantially alter the project's overall work force and concomitant population effects. These factors are also shaped by the management philosophy of a project's sponsor and perhaps most fundamentally by the time frame in which the development occurs. In the absence of a definite development time table or sponsor and without knowledge of the engineering, design, and overall facility configuration that could prevail at NOSR 1, it is difficult to formulate accurate estimates of employment and population effects.

18-12 Characteristics of the resource limit technology choice to some degree but do not dictate that a single process is the only acceptable one. The DOE did not "reject other technologies" in the sense implied in the comment. Refer to the selection criteria on pages 3-1 and 3-2 for the rationale of considering the Colony process as representative for EIS purposes.

18-13 The estimate of 400,000 BPD as the maximum production limit that could be achieved without violating the PSD increments for Flat Tops was based upon extrapolations of Valley Modeling results. However, this estimate is conservative and EPA unofficially estimates that the limits are probably in the range of 800,000 to 1,200,000 BPD. No one accepts any of these estimates as being other than an educated guess, and well outside the model validity.

18-14 The status of the air quality control district for the oil shale region was incorrectly represented in Figure 3-4 and has been changed. Due to a reinterpretation of data and law, Rio Blanco and Garfield Counties are considered attainment areas for particulate matter even though Mesa County is a nonattainment area.

18-15 Refer to the discussion on page 3-6 and to the response to comment 12-16.

18-16 The chart on page 3-24 has been modified. It serves to show the various population changes which would probably occur as the results of each alternative. The discussion does not suggest that a concentrated 50,000 BPD ethanol operation would be constructed. Rather, on page 3-23 it is stated that "some spreading out of the 14 alcohol plants is likely, and any one community would experience only a fraction of the indicated population increase." Therefore, the socioeconomic impacts would be significantly less for decentralized rather than centralized alcohol production. The expenditure levels for biomass are based on the estimated cost of constructing 14 separate 3,600 BPD plants.

18-17 We agree with the statement that new town planning and other mitigation efforts will not make socioeconomic impacts of large-scale industrial development "insignificant." However, the contrary was never intended to be portrayed in the PEIS. The distribution between an effort to "lessen the significance of socioeconomic impacts" and the total elimination of such impacts is one of potentially infinite proportions.

The statement that "no one knows whether Battlement Mesa will work" presents several key issues with regard to community development and impact mitigation. The first is that no one could "know" whether any impact mitigation strategy will succeed or fail until all the results are in. Also, even after any community development plan has been in place for years, there is a possibility that there will be no consensus as to whether or not it has "worked," as that term implies a multitude of subjective judgments which must be made to evaluate the plan's effectiveness in mitigating impacts.

Finally, the implication that uncertainty of outcome is an insurmountable barrier to action contains as its basis philosophical considerations which are beyond the scope of this discussion.

18-18 Analyses of plant life revenue and front-end revenues are both relevant to a detailed discussion of fiscal impacts. As an example, projected revenue surpluses in the latter years of the project could be pledged to finance front-end costs, through municipal bonds guaranteed by participating companies or through prepayment of taxes. However, we agree that front-end financing is among the ultimate fiscal impact issues.

18-19 Site-specific socioeconomic baseline data were developed for the NOSR 1 study area only.

18-20 The comment correctly states that mercury and arsenic may be significant non-criteria pollutants. The text has been ammended.

18-21 Refer to the response to comment 2-8.

18-22 A hypothetical projected reduction in vehicle miles traveled (VMT) is another possible way of representing the conservation alternative. Refer to the response to comment 5-1(G) for a further discussion of the conservation option.

18-23 Biomass emissions were revised. Refer to the response for comment 3-10 for a discussion of EIS versus OTA emissions estimates.

18-24 Revised emissions for biomass are reflected in all discussions.

18-25 Biomass water requirements have been revised.

18-26 Refer to the response to comment 3-17 for a discussion of NOSR versus OTA water estimates. Page C-3, listing NOSR operating parameters, states NOSR net raw water requirements are 73,714 BPD. NOSR shale oil production is listed as 50,250 BPD, a ratio of 1.467 gallons of water per gallon of shale oil. The analysis which resulted in the design of the reference plant for NOSR predates the Programmatic EIS by about a year, and did not deal with water conservation explicitly. More recent conceptual designs for NOSR show possible water/oil ratios ranging from less than 2 to over 4, but these results are not in any document suitable for referencing at this time.

Rio Blanco Natural Gas Co.
2000 WESTERN FEDERAL SAVINGS BUILDING
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(303) 292-1350

December 8, 1980

G. R. Gilmore
Captain, CEC, USN
Director, Naval Petroleum and
Oil Shale Reserves
Department of Energy
Washington, D. C. 20461

RE: Colorado Oil Shale

Dear Captain Gilmore:

Thank you for your November 26, 1980 letter. I would be pleased to have my company's comments included in the final Environmental Impact Statement for the Naval Oil Shale Reserves, Garfield County, Colorado.

Sincerely yours,

RIO BLANCO NATURAL GAS CO.

Robert E. Chancellor

Robert E. Chancellor
President

RECEIVED
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WASH, D.C.

Rio Blanco Natural Gas Co.
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December 8, 1980

Secretary Charles W. Duncan, Jr.
U. S. Department of Energy
M/S 7E-054, Forrestal Building
Washington, D. C. 20585

RE: Government Financial Involvement In Oil Shale Development: Occidental - Tenneco Request For Federal Loan Guarantees For Prototype Oil Shale Tract C-b, Rio Blanco County, Colorado

Dear Secretary Duncan:

The subject request for $3+ Billion in loan guarantees calls for a review of the history of this tract and the present operator's plan for its development.

This tract was originally selected for leasing because it was thought that although the depth to the richer oil shale values exceeds 1,000 feet and the lower half of the 1,700 foot thick target rocks exhibits porous and cavernous zones containing water and natural oil and gas; knowledge gained from work done by and at the expense of private industry concerning methods to exploit the Kerogen rich lower zones would justify the leasing of the tract. The original plan of development called for underground mining into these lower zones.

The initial purchasers of the lease relinquished their interest therein and through a series of complex negotiations, Occidental Oil Shale, Inc. and Tenneco Oil Shale Company have become operators of the lease. Their present extraction plan is for modified in situ burning of the oil shale rocks overlying the lower sequence -- this primarily in the Mahogany zone. Occidental has for some time, with government assistance, been conducting pilot in situ extraction from the Mahogany zone in the Rifle area which it has indicated to be commercially viable.

Thus, detrimental to the public interest, the original purpose for granting this lease in the area of the richest oil shale values is now negated. The planned in situ extraction work in the upper half of the oil shales on Tract C-b could very well preclude any future opportunity to recover the more than 1 billion barrels of shale oil in the lower half of the sequence.

In the rush to achieve commercial scale shale oil production, this unfortunate circumstance should not be overlooked. If the government is inclined to some sort of financial assistance to the Tract C-b operators, that assistance should be limited to a return to the original purpose of the leasing, which included efforts to evolve extraction methods for the lower half of the oil shale sequence.

Sincerely yours,

RIO BLANCO NATURAL GAS CO.

Robert E. Chancellor

Robert E. Chancellor
President

cc: Attached List

Copies of Letter dated December 8, 1980 to Secretary Charles W. Duncan, Jr., U. S. Department of Energy; RE: Government Financial Involvement in Oil Shale Development - to:

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→ G. R. Gilmore
Captain, CEC, USN
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RESPONSE SET 19

These comments do not raise any specific issues which require an agency response in this EIS.

PHILLIPS PETROLEUM COMPANY
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October 27, 1980

Dr. C. M. Wong
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12th and Pennsylvania Avenue, N.W.
Mail Stop 3344
Washington, D. C. 20461

Dear Dr. Wong:

We would like to offer the following comments in connection with the Draft Programmatic Environmental Impact Statement (DEIS) development policy options, Naval Oil Shale Reservations, Garfield County, Colorado.

20-1 We believe the United States oil shale resources should be expeditiously developed in order to reduce our dependence on imported oil. The development of oil shale on Federal land beyond that presently subject to lease is certainly desirable. The Naval Oil Shale Reserves in Colorado should be developed in connection with this program.

20-2 These reserves could best be developed through a Federal leasing program with free market mechanisms as financial incentives.

Sincerely,

C. A. Wentz

C. A. Wentz
Oil Shale/Oil Sands Manager

CAW:bh

RESPONSE SET 20

No response necessary.

OXY

OCCIDENTAL OIL SHALE, INC.

P. O. BOX 2687 751 HORIZON CT. • GRAND JUNCTION, COLORADO 81502
(303) 242-8463

December 5, 1980

W. F. McDERMOTT
Executive Vice-President

Mr. Don Silawsky
Naval Petroleum and Oil Shale Reserves
12th and Pennsylvania, N.W.
Mailstop 3344
Washington, D.C. 20461

RE: Draft EIS, Naval Oil Shale,
Colorado, DOE

Dear Mr. Silawsky:

Thank you again for returning the telephone call on Tuesday, December 2, to our Denver office and the discussion on the Draft EIS on NOS-1&3. Your offer to review written comments until around the middle of December is appreciated. Some specific comments include:

21-1 1. Statements on pages 3-10, 3-12 in Appendix C indicate development of NOS-1&3 is more net energy efficient than other oil shale development and the other four energy development options with the exception of additional OCS leasing. Firm data from other oil shale operations to support this conclusion are inadequate.

21-2 2. The air pollution emissions and water requirements on pages 3-13, 5-3, and 5-15 are based on Colony EIS, TOSCO II stipulated data and assumptions. Review of these data and current PSD requirements merits consideration.

21-3 3. The discussion in Appendices B and C concerning cost of operation for a 50,000 BPD plant between either a producer or a government-run operation needs careful review and rewrite, especially in comparison to the DOE recently received solicitation under the Federal Non-Nuclear Research and Development Act.

It is requested that the comment period be extended into early 1981 in order that the incoming Administration be afforded an opportunity to review this and other outstanding draft EIS's.

Very truly yours,

W. F. McDermott

WFM/cj

A SUBSIDIARY OF OCCIDENTAL PETROLEUM CORPORATION

RESPONSE SET 21

21-1 Based upon the energy requirements analysis in the Programmatic EIS and reinforced by the results of Appendix G, the conclusions drawn in the EIS appear correct.

21-2 The EIS was revised to reflect emissions levels from the Colony PSD permit.

21-3 The need for further review and rewrite "concerning cost of operation between either a producer or a government run operation" is not apparent and the comment concerning those needs is not sufficiently explicit to define the objectives of such a review. The relevance of "the DOE recently received solicitation under the Federal Non-Nuclear Research and Development Act" to the NOSR 1 EIS or its impact upon the relative cost of operation between "a producer or a government-run operation" is also not apparent.

PUBLIC HEARINGS
FOR THE
DRAFT ENVIRONMENTAL IMPACT STATEMENT
DEVELOPMENT POLICY OPTIONS
NAVAL OIL SHALE RESERVES
GARFIELD COUNTY, COLORADO

Tuesday, november 18, 1980
Ramada Inn Convention Center
Grand Junction, Colorado

2:00 p.m.

HEARING PANEL

JACK O'BRIEN, Regional Environmental Coordinator, D.O.E.

LEE BRENNAN

WILLIAM GOODE

DON SILAWSKY

MICHAEL R. FOSDICK, Director of Engineering, NPOSR

KAREN MAHER
Registered Professional Reporter

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by Mr. Silawsky	20

THE FOLLOWING PROCEEDINGS WERE HAD AND DONE, TO-WIT:

MR. O'BRIEN: Good afternoon, and welcome. My name is Jack O'Brien. I'm the moderator for this afternoon's meeting. I'm also the Regional Environmental Coordinator for the Department of Energy, stationed in Denver.

Joining me on the panel this afternoon are Lee Brennan, Deputy Director of the Office of Naval Petroleum and Oil Shale Reserves; Bill Goode, Evnironmentalist, Office of the Assistant Secretary for Resource Applications; Don Silawsky, Environmentalist for the Naval Oil Shale Reserves; and Mike Fosdick, Director of Engineering for the Naval Petroleum and Oil Shale Reserves, stationed in Casper, Wyoming.

The Department of Energy, and I will refer to that as DOE, has prepared a draft environmental impact statement in accordance with the National Environmental Policy Act in order to assess the environmental impact of proposed policy options to develop the 55,000 acre Naval Oil Shale Reserves, and I'm going to refer to those as the NOSR's, Naval Oil Shale Reserves 1 and 3 near Rifle, Colorado.

Commercial scale production is forseen, ranging from one 50,000 barrel per day facility to several facilities producing up to 200,000 barrels per day, which is currently viewed as the maximum potential from the NOSR-1 and NOSR-3 oil shale reserves.

I beg your pardon, can you hear me better now? I hope we were able to pick up all of that.

At this maximum production of 200,000 barrels per day, the recoverable reserves of high grade oil shale from NOSR's 1 and 3 would be exhausted in approximately 25 years. NOSR shale oil development policy options include: (a) leasing large parcels to industry; (b) joint government/ industry ventures; (c) government-owned/contractor-operated ventures; and (d) quasi-utility ventures.

Now, the law requires the President and Congress to approve any action that DOE proposes to take. This meeting is the third step in the Department's EIS process. The first was when DOE conducted public EIS scoping meetings in Grand Junction and Denver on February 5 and 7, 1980. The second was the publication in September 1980 of the Draft Programatic EIS. The fourth step will be publication of a Final EIS, followed by the final step of publishing a record of the decision.

The public is invited to submit written comments or suggestions for consideration by DOE in preparation of that final EIS, as well as participate in any of the meetings which are being held both today in Grand Junction and Denver the day after tomorrow. Input from these meetings will assist us in preparing the final EIS.

Written comments should be received at DOE by

November 28, 1980, to insure consideration in the preparation of the final EIS. The public meetings are scheduled to be held again here in Grand Junction, and then in Denver day after tomorrow.

All comments may be sent to Donald Silawsky, Environmental Project Manager, Naval Petroleum and Oil Shale Reserves, U.S. Department of Energy, 12th and Pennsylvania, Northwest, Mail Code RA-3344, Washington, D.C., 20461. He may be contacted by phone at Area Code 202, Exchange 633-8641.

Now, that information will be available to anyone who wishes it. If they will just come forward following the meeting, I will make sure you have that address and that phone number.

Congress gave the Department of Energy control over the Naval Oil Shale Reserves in 1977. DOE has since been investigating the potential to develop a large-scale mine and production facility there as a means of increasing the nation's supply of domestic fuel.

NOSR-1 and NOSR-3 were withdrawn from the Navy by executive order in 1916 and 1924 as potential reserves of military fuels. In 1962, Public Law 87-796 gave the Secretary of the Navy the same authority to develop the NOSR's as he has for the Naval Petroleum Reserves. In 1977, Public Law 95-91 transfered the jurisdiction over the Naval Petroleum and Oil Shale Reserves from the Navy to the Department of

Energy.

Stemming from the increased awareness of domestic production needs which resulted from the Arab Oil Embargo of 1973-74, a multi-year pre-development plan for NOSR's 1 and 3 was prepared by the Navy and was submitted to Congress. This plan was approved in 1977. The initial objective of the plan was to assess the oil shale and water resources of NOSR 1 and 3, develop environmental base line data, and determine the most suitable development scenarios for NOSR 1 and 3. The goal of this 1977 plan was to prepare a master plan for government development of commercial shale facilities on NOSR 1 and 3.

In late 1978, the plan was divided by DOE into two phases. The first is an environmental base line determination as well as a resource and technology assessment, both to be completed in late 1981. The second is an environmental impact analysis and an EIS with the requisite supporting preliminary engineering for a site-specific commercial-scale facility. Phase one and two can serve to maintain the momentum and timeliness of all of the options of leasing, joint venture, of government facilities, under any contingency. The draft EIS described in this notice -- the notice for today's meeting -- will use information developed in Phase one and in DOE's overall oil shale program to discuss the impacts of the various policy options to develop NOSR

1 and 3 in Colorado.

The funds to develop the NOSR's under the several policy options considered in the EIS -- that is lease, industry partnership, government ownership, and so forth -- have not yet been authorized by Congress. The EIS will be included in any DOE recommendation to Congress for NOSR development.

Currently there are two major heating, that is retorting, processes developed by industry to retort oil from shale: surface and modified in situ. Both involve the steps of mining, extraction, and upgrading to some degree. Transportation of the shale oil from the site to a refinery market is the last major step.

A 50,000 barrel per day surface retorting facility producing upgraded oil from 30-gallon-per-ton oil shale will require the mining and crushing of about 70,000 tons of oil shale per day. About 85 percent of this tonnage must be disposed of on the surface as spent shale. It may be possible, however, to return a large portion of that spent shale to the underground rooms.

In the modified in situ, that is underground or in-place process, 20 to 40 percent of each retorted column is mined to create a void. The remaining rock is rubbilized and retorted by firing in place. The shale oil is then pumped to the surface.

There are approximately 17 options available for extracting oil from shale. These fall broadly into the categories of retorting, solvent processing, and bio-leaching.

Retorting, the most widely used method, heats oil shale either in an above-ground vessel or in situ, to the temperature at which kerogen, the organic material within the ore, is decomposed into gas, condensable oil, and a solid residue. The rate of kerogen decomposition is high at retort temperatures of 900 to 950 degrees Farenheit, and complete decomposition occurs within a few minutes. Product characteristics are similar to those products obtained from thermal cracking and coking of petroleum.

Upgrading describes on-site methods of improving the flowability and the chemical properties of shale oil and gas. The methods used are commonly practiced in the petroleum refining industry during conversion of petroleum into finished products, that is gasoline, diesel fuel, and things like that; but modified to accomodate the special characteristics of shale oil. A minimum of upgrading is necessary to transport shale oil through unheated pipelines.

The following environmental issues were among those addressed in the draft EIS. This list was not all inclusive, nor was it intended to be a predetermination of impacts.

The effects of the labor market resulting from the development options, and the effects of the resulting labor immigration on the local infrastructure was the first considered. Number two, the effects of the proposed development options on the communities in Garfield and Rio Blanco counties of Colorado. Number three, the effects of NOSR development options on tax bases. Number four, the general effects of oil shale mining, storage, disposal, and plant runoff on surface water and ground water quality and aquatic ecology. Number five, the general effects of the proposed options on air quality, including the combined effects with other major or planned emission sources in the area.

Number six, the effects of potential accidents and product releases on water supply and ecology. Number seven, the effects of each development option and operation on present and future land use and terrestrial ecology. Number eight, the effects of development on local water resources, including the Colorado River. Number nine, the effects of spent shale disposal. Number ten, the effects of transporting the shale oil from the site to a refinery.

For each of the four proposed development policy options, significant economic issues were also addressed in detail. Some of the major issues for each option are as follows: For leasing it, maximum parcel size, royalty terms; lease payment schedule, diligence requirements.

For government/industry joint venture or GOCO, mix of ownership -- I beg your pardon, this is for joint industry venture. A mix of ownership, investment/payment schedules.

For the GOCO venture, treatment of sales and fee schedules. And for the quasi-utility venture, government definition and control of rate of earnings.

The final EIS will examine and compare the environmental effects of NOSR policy options as well as reasonable alternatives to NOSR-1 and 3 development, including, one, no action; two, increased conservation; three, oil shale development on other land; four, enhanced oil recovery; five, outer continental shelf oil production; six, coal liquifaction; seven, tar sands; and eight, biomass and alchohol production.

Now, all interested parties have been invited to attend the meetings both here and in Denver, and to submit comments or suggestions in connection with the preparation of the final EIS. Written comments or suggestions may be submitted in lieu of or in addition to participation at these meetings. Those desiring to submit comments or suggestions to be addressed in the final EIS should submit them to Mr. Silawsky, and again we have given you that address before and we will give it to you after the meeting if you desire to contact him that way.

This meeting will not be conducted as either an evidentiary or an adversary hearing. Those who choose to make statements may not be cross-examined by other speakers. However, members of the panel may ask the speakers questions needed to clarify statements or positions advocated.

The purpose of the meeting is to give you, the public, the opportunity to participate in the decision-making process. We from DOE are here to learn and to listen.

Now, in order to provide the Department of Energy with as much information as possible, and with as many views as can reasonably be obtained, and to provide interested persons with equitable opportunities to express their views, we have adopted the following guidelines: Speakers will be called on to testify in the order they sign in, provided they express their interest to speak. Should any speaker desire to provide additional information for the record, it may be submitted in writing no later than November 28, 1980. Written comments will be considered and given weight equal to oral comments.

A transcript of this meeting will be retained by DOE and made available for inspection at the Freedom of Information Library, Room GA-152, Forrestal Building, 1000 Independence Avenue, Northwest, Washington, D.C. 20585, between the hours of 8 a.m. and 4:30 p.m., Monday through Friday. Upon completion of the final EIS, it will be available at DOE and in the public libraries of Grand Junction and Denver.

Those not desiring to submit comments or suggestions at this time, but who would like to receive a copy of the final EIS when it is issued, should also notify DOE. Those seeking information in this regard should also contact Mr. Silawsky.

All suggestions, comments and questions submitted to DOE by November 28, 1980 will be carefully considered in the preparation of the environmental impact statement.

We appreciate your interest in the process, and welcome you to today's meeting, as well as any future DOE meetings.

I would like now to call upon Lee Brennan to discuss some specific issues on the draft EIS. Lee?

MR. BRENNAN: Good afternoon, Jack. What I would like to do is give you a little bit of a perspective on where this impact statement sits in the overall decision process of the Department of Energy regarding the Naval Oil Shale Reserves.

First we will go to a map. For anybody who is not familiar with the property we are talking about, the Naval Oil Shale Reserves are located a few miles northwest of Rifle, and about 60 miles east of Grand Junction.

The draft EIS that we are dealing with here forms one of these building blocks of the decision process on what to do, what is the best method to utilize Naval Oil Shale

Reserves. The first step in that process is to analyze in a generic manner impacts associated with the proposed action, that is development; to compare that analysis with other alternatives for accomplishing an objective; and to identify a preferred alternative.

A key element of that process is what we are here for today, which is to elicit comments from the public, and we also gather comments from appropriate government agencies.

The document that we are dealing with now is a programatic environmental impact statement which deals with the broad policy options. The decision that comes from this document would then lead us to a site-specific environmental impact statement which would deal with a specific project at a specific site.

Now, where this fits in a hypothetical schedule for any development at the NOSR's, the programatic EIS is part of the predevelopment program, which, as you can see, runs through early 1984. That program will generate a considerable amount of documentation, which would be submitted through the Administration to Congress. Any further work beyond this predevelopment or study phase would require Congressional approval. Again it would also require going through the Administration channels of the Office of Management and Budget, and up through the White House. Okay.

The predevelopment plan of program itself is broken

READEX FICHE

into many components. The one we are concerned with revolves around the phase one decision and the programatic EIS. Now, based on the decision that comes out of this phase, which the programatic EIS will be packaged with what we call a decision package, an action memoranda that will be sent up through the Department of Energy.

Based upon that decision, we will then scope this second phase, which begins in late '81 into '82, of the predevelopment program. The basic elements will remain, but they will be scoped to fit with the decision that should come out sometime in 1981.

Finally, again that decision that we are dealing with is the basic decision of should the NOSR's in Colorado be developed at all? If so, in what manner should they be developed? For example, lease, joint venture, government venture, GOCO or utility-type venture.

So I hope that gives you a little better perspective of how the EIS fits in with the DOE policy making.

Now I would like to turn it back to Jack, and we can get on with the business at hand, which is to receive your comments. Thank you.

MR. O'BRIEN: I don't think we had a sign-in sheet for those of you who wish to make a presentation or give comments today. So at this time I would ask those of you who do wish to comment to raise your hands, and I will then call upon you.

We have the travelling microphones we will bring to you. Please, identify yourself and who you represent, if anybody other than yourself, just for our records, please.

The first gentleman here?

TED NATION: My name is Ted Nation. I represent the Two Rivers Citizens Association of the Grand Junction area. I have a rather extensive comment, so I don't know whether it's best to do it here, but I will try.

I have reviewed your document and found it weak in design and woefully inadequate in its treatment of the chosen alternatives. However, even within these serious limitations, your draft EIS clearly shows that the conservation alternative is infinitely superior to any of the oil shale alternatives, both from an environmental and socio-economic standpoint. In fact, the conservation alternative is rapidly being implemented by the market as consumers purchase lighter weight and more fuel-efficient cars, and fuel imports continue to drop dramatically without any appreciable increase in domestic production.

The scope for continued increases in efficiency remain dramatic, however. The passenger car fleet still averages in the 15 mile per hour range, or 15 mile per gallon range, with 30 miles per gallon common in newer fuel-efficient vehicles, and 70 to 80 miles per gallon being attained in some research vehicles. The tragedy is that the Amercian auto industry and workers are suffering such dramatic dislocation while the federal government pours resources into risky, untried technologies like oil shale rather than into assisting the development of domestic fuel-efficient vehicles and dwellings.

The scope for cost-effective energy efficiency improvements is well documented. Whether one choses to accept the more dramatic studies such as Gerald Leach's A Low Energy Future for the United Kingdom, or more conservative studies such as the Harvard Business School study, it is clear that there is dramatic room for improvements in energy efficiency that are cheaper, faster and more environmentally benign than oil shale, and are socially productive rather than disruptive.

Energy use projections continue to fall. Six years ago the energy companies and the federal agencies were predicting energy use in the year 2000 of 190 quads or more, while end use analysis was yielding results in the 124 quad range. Now the energy companies and federal agencies are down to 124 quads or less, and end use analysis is yielding estimates of 75 quads to 63 quads.

All of this leads me back to the weaknesses in your study. 22-1(A) The conservation alternative chosen was only one of many, and the implication was left that all alternatives were

22-1(A) cont.

needed rather than examining the vast scope of savings available in energy efficiency investments and their economic, social and environmental costs versus oil shale. In other words, how many billions could be invested in energy efficiency, particularly where it saved liquid fuels or fuel that can be easily substituted for liquid fuels in some applications before these investments ceased to be cost effective against oil shale? Many studies indicate the scope of such cost effective investments are in the hundreds of billions of dollars before considering environmental and social effects.

22-1(A) cont.

Your treatment of biomass conversion also suffers similiar weakness in its limited scope. However, a more serious defect occurs as a result of the report's tendency to treat all impacts as equal without regard to degree. For instance, one 3,600 BPD ethanol plant located in a Midwest farm community might very well be socially beneficial by adding moderately to the job base, making the community more energy independent, et cetera. Such facilities could be scattered over a wide area in the Midwest and Southeast without serious social disruption.

Oil shale, on the other hand, will be produced in a sparsely populated, confined region of Western Colorado and eastern Utah. In reality, most of the early production will take place in a 50 mile by 50 mile region known as the

Piceance Creek Basin. Here a rapid expansion of the population beyond ten to 15,000 people will have major socio-economic and environmental consequences.

By far the most serious weakness of the draft EIS
is its shoddy treatment of the impacts of the industry upon
our communities and environment. Almost all discussion of
socio-economic impacts compare long-term total tax revenues 22-1(B)
with per-year expenses for infrastructure and human
services. This long-term treatment, rather than looking at
the short-term problems, which are the most serious problems
for the community, is a serious weakness in itself. More
importantly, however, is the failure to focus on the human
impacts. Where is the discussion of inflationary impacts on
all current residents? Where is the discussion of the
alienation that will take place? What are the costs assigned 22-1(C)
for the elderly who will no longer be able to afford to live
in their own communities? What about the increased crime
and alchoholism that accompanies such growth? Socio-economic
impacts are not just a numbers game. They involve people.
They involve us.

Utilities are hardly mentioned. However, any of
us familiar with the subject know the impacts on electrical
supplies alone will be massive and are already threatening 22-1(D)
communities all over the Western Slope. We also are aware
that new facilities cost a great deal more than they used to.

The marginal costs of new electric generating capacity is estimated to be between 6.5 and 8.5 cents per kilowatt hour. Current charges to residential customers are in the 4.5 to five cent per kilowatt hour range.

Every plant and transmission line that is built gets added to the rate base and current users see their bills climb to subsidize new growth and new industries that many of them don't want in the first place. The environmental consequences of such utility development is also severe. As many as eight new 200-megowatt plants may be built at Loma and Delta over the next few decades. The Grand Valley area is already a non-compliant air quality region with serious air inversions in the winter. What will be the consequences of one, two or four such facilities near Loma?

Similarly, transmission lines are planned from Rifle, over the end of Grand Mesa, down the North Fork Valley, over the Uncompahgre Plateau, through Dolores, winding up in San Juan, New Mexico. What are the environmental and quality of life consequences of such major activity?

I realize your report is not designed to deal with the total industry impact, but that is the problem. Here is another decision document trying to treat the impacts piecemeal, while our area faces a federally-mandated and subsidized expansion of the industry to 400,000 barrels per day by 1990 without any comprehensive study of regional impacts on communities or environment.

22-1(E)

Similarly, there is no discussion of the down-side effects on our region if the industry gets underway, proves uneconomic against alternatives, or technically unfeasible, and collapses. The companies have federal guarantees, but our communities don't. We will be left with mortgaged communities with perhaps thousands of unemployed people. The resulting slump could be many times worse than the ups and downs that have occurred in the government-stimulated uranium industry, because the traditional economic base will be smaller and, relative to the industry, much smaller.

I strongly urge that the federal government adopt the no action alternative on NOSR-1 and 3, no matter what happens with the other projects now underway. Allow us to gain some experience with the consequences of the smallest possible commercial scale industry before stimulating activity even more. Concentrate your efforts on the much more productive and benign investments in energy efficiency and renewable resources.

Gentlemen, we don't have an energy shortage, only a shortage of cheap energy. Certainly oil shale is not a cheap source. Thank you.

JACK O'BRIEN: Now, are there any other comments from the audience?

LAWRENCE ZUCKERMAN: My name is Lawrence Zuckerman.

I'm working on a grant for the National Wildlife Federation in the Parachute Creek area, and am also a Ph D student at the Colorado State University.

22-2 What I see in your beginning proposal here, I don't see a mention of a threatened fish which is classified by the State of Colorado, the Colorado River Cutthroat, which is salmo clarki pluridus. There are known populations in the North Water Creek and East Fork of Parachute Creek.

I want to know if anybody is going to look at the plans, see what kind of impacts and any kind of mitigation that can be done concerning this threatened fish.

That's about it, thank you.

MR. O'BRIEN: Thank you, sir.

Any further comment? Would you like to --

MR. SILAWSKY: Let me respond to that one last question. Right now we are pretty much right at the beginning of a very extensive environmental survey of the NOSR-1 lands. This environmental survey includes detailed investigations of air quality, water resources, both underground and above ground; animal life, plant life, and all the other attendant components of a full-scale environmental survey.

Most importantly, this species of fish you mentioned would certainly be, you know, surveyed if the decision is made to develop the reserves, at which time a site-specific environmental impact statement would have to be developed. But I would just like to, you know, emphasize again that we are right at the beginning phases of a full-scale environmental background survey of NOSR lands. So we appreciate your bringing it to our attention the existence of this species. I'm sure it will be included in the data that we develop.

MR. O'BRIEN: Are there any further comments from the audience? Any questions?

Well, we have the afternoon until five o'clock.

TED NATION: Why did you change the time of your meeting from seven o'clock to the middle of the afternoon when the working people were busy?

MR. O'BRIEN: Pardon me, will you please ask your question again?

TED NATION: I wanted to know why you changed the time of your meeting from seven o'clock at night to the middle of the afternoon when it's very difficult for working people to attend.

MR. O'BRIEN: The official publication came out with the afternoon time.

Well, the meeting will remain open this afternoon until five o'clock for any of those of you who wish to make further comment or for discussion. The panel will be available for discussions with anybody.

Again if you want the address for getting the information from this meeting or for getting copies of the final EIS, I would suggest you get with Mr. Silawsky and get his address so you can contact him.

So we are in a stand down position. The meeting is not adjourned. We are open until five o'clock this afternoon.

Thank you all for coming. If you have any further word you want to give us, please get it to us by the November 28th date. We want to have your ideas and your concerns included in this EIS. Thank you very much.

(The hearing was recessed at 2:45 p.m.)

I, KAREN MAHER, a Registered Professional Reporter and Notary Public of the State of Colorado do hereby certify that the foregoing is a true and accurate transcription of my stenotype notes, taken by me at the time and place aforementioned.

KAREN MAHER
Registered Professional Reporter

RESPONSE SET 22

22-1A The conservation alternative was chosen to represent the wide range of conservation options available to the country. In fact, it is one of the cleanest of such options, directly reducing pollution without providing any of its own, such as would a mass transit option.

The EIS objective is to evaluate and compare the impacts of liquid fuel alternatives, and not to set priorities on national energy options. As a representative case, the conservation option selected for comparison is considered to be a very favorable example.

All impacts are treated as equal in terms of including quantitative estimates of all the available first-order, or direct, impacts as the basis for comparison. The comment referring to the "shoddy treatment of the impacts of the industry upon our communities and environment" identifies second-order socioeconomic impacts. These are, of course, very important, as are numerous other second-order impacts of all kinds, depending on the interests of the commenter. The first-order, or direct, socioeconomic impacts are provided in the document as the basis for comparison, and these do reflect the relative problems, although not as vividly as would the higher order impacts.

22-1B While the level of detail of the discussion of fiscal impact issues in the EIS is somewhat general, we believe that the important factors, both long and short term, were discussed at a level adequate for this programmatic document. A more comprehensive examination of such issues is premature at this time because the information upon which a detailed analysis of front-end financing requirements must be based is not yet available and a discussion of specific amounts of such requirements would be meaningless without such a detailed analysis.

22-1C The sociological impacts resulting from the development of oil shale are typical of labor-intensive energy projects. The rapid influx of population into a rural area creates major changes in both the social and economic environments. The increase in population also increases the demand for housing, goods and services which typically results in rapid inflation. People on low or fixed incomes are particularly impacted by the rise in prices. Communities in the oil shale region are already experiencing many of the boomtown effects associated with energy development. The crime rate increases even more rapidly than the population growth, divorces increase, and many new and long-term residents suffer the stresses of a community undergoing rapid changes.

It is possible that the NOSR project will affect the absolute level of such impacts in the region. However, to suggest, as the comment apparently does, that the NOSR project will significantly alter the nature of social impacts associated with large-scale energy development in the region is to ignore the pre-existing development which is already occurring in the Piceance Basin, prior to the initiation of the NOSR project.

22-1D Detailed and regional industrial impacts such as these were not considered appropriate for a conceptual discussion such as was contemplated by the EIS, as the comment surmises.

22-1E The issue presented by this comment, that of the risk of collapse of the oil shale industry, is one which is clearly beyond the scope of analysis of the EIS, as it involves questions of international demand for the product of the project--namely shale oil. However, the project's fundamental purpose is to ensure a long-term flow of oil which is independent of national and international conditions and circumstances which might otherwise interrupt that flow. Therefore, and because the project is supported by a long-term need for a defense-based fuel supply, rather than the short-term vagaries of the private market, the certainty of continuous production under the NOSR development alternatives may be somewhat greater than under a strictly private oil shale development.

22-2 On-site data from a recent endangered species survey have been included in the affected environment section for NOSR 1.

22-16 The sociological impacts resulting from the development of oil shale are typical of labor-intensive energy projects. The rapid influx of population into a rural area [illegible] changes in both the social and economic environments. The increase in population also increases the demand for housing, goods and services which generally results in rapid inflation. People on low or fixed incomes are particularly impacted by the rise in prices. Communities in the oil shale region are already experiencing many of the boomtown effects associated with energy development. The crime rate increases much more rapidly than the population growth, divorces increase, and both new and long-term residents suffer the stresses of a community undergoing rapid changes.

It is possible that the NOSR program will affect the absolute level of such impacts in the region. However, to suggest, as the comment apparently does, that the NOSR project will significantly alter the nature of social impacts associated with large-scale energy development in the region is to ignore the pre-existing development which is already occurring in the Piceance Basin, prior to the initiation of the NOSR program.

22-18 Detailed sub-regional industrial impacts such as these were not considered appropriate for a programmatic discussion such as was contemplated by the EIS, as the comment requires.

22-19 The issue presented by this comment, that of the risk of collapse of the oil shale industry, is one which is clearly beyond the scope of analysis of the EIS, as it involves questions of international demand for the product of the [illegible] shale oil. However, the program's fundamental purpose is to ensure a long-term flow of oil which is independent of national and international conditions and circumstances which might jeopardize that flow. Therefore, and because the project is supported by a long-term need for a dependable fuel supply, rather than the short-term vagaries of the private market, the certainty of continuing production under the NOSR development alternatives may be somewhat greater than under a strictly private oil shale development.

PUBLIC HEARINGS

For the

Draft Environmental Impact Statement

Development Policy Options

Naval Oil Shale Reserves

Garfield County, Colorado

November 20, 1980, 2:00 p.m.
Federal Building, Room 239
19th and Stout Streets
Denver, Colorado

APPEARANCES:

Jack O'Brien
Lee Brennan
William Goode
Don Silawsky
Michael Fosdick

PROCEEDINGS

MR. O'BRIEN: Good afternoon, Ladies and Gentlemen, and welcome. My name is Jack O'Brien, and I am the moderator for this afternoon's meeting. I am also the regional environmental coordinator for DOE, and I work with the Special Project Office in Denver, which is responsible for managing the Phase One Surface Oil Shale Demonstration Project.

Joining me on today's panel are Lee Brennan, Deputy Director of the Office of Naval Petroleum and Oil Shale Reserve; Bill Goode, Environmentalist, Office of the Assistant Secretary for Resource Applications; Don Silawsky, Environmentalist for the Naval Oil Shale Reserves,. and Mike Fosdick, Director of Engineering for the Naval Petroleum and Oil Shale Reserves in Casper, Wyoming.

The Department of Energy, DOE, has prepared a draft envornmental impact statement in accordance with the National Environmental Policy Act in order to assess the environmental impact of proposed policy options to develop the 55,000 acre Naval Oil Shale Reserves, which I will refer to hereafter as NOSR, N-O-S-R, near Rifle, Colorado.

NOSR oil development policy options include: (A) Leasing large parcels to industry, (B) Joint government/industry ventures, (C) Government-owned-contractor-operated, GOCO, ventures, and (D) quasi-utility ventures.

Of course, the law requires the President and the Congress to approve any action that DOE proposes.

Commercial scale production is foreseen, ranging from one 50,000 barrel per day facility to several facilities producing up to 200,000 barrels per day, which is currently viewed as the maximum potential from the NOSR-1 and NOSR-3 oil shale reserves. At this maximum production rate, the recoverable reserves of high-grade oil shale from NOSR-1 and 3 would be exhausted in approximately 25 years.

This meeting today is the third step in the department's EIS process. The first involved DOE-conducted public EIS scoping meetings in both Grand Junction and Denver on February 5 and 7 in 1980. The second step was a publication in September of this year of the draft programmatic EIS.

The fourth step will be publication of a final EIS, followed by the final step of publishing a record of the decision.

The public is invited to submit written comments or suggestions for the consideration by DOE in the preparation of the final EIS, as well as to participate in any of the meetings, including this one this afternoon. Input from these meetings will assist DOE in preparing the final EIS.

The written comments should be received at DOE by November 28, 1980, to ensure consideration in the preparation of the final EIS.

The public meetings are scheduled -- we held one the day before yesterday in Grand Junction. We are holding this one this afternoon, and there will be another one here at this same location tonight at 7:00 o'clock.

All comments should be sent to, and I will read this rather slowly so that you can take down the address, Donald Silawsky, S-i-l-a-w-s-k-y, Environmental Project Manager, Naval Petroleum and Oil Shale Reserves, U. S. Department of Energy, 12th and Pennsylvania, N.W., Mail Code RA-3344, Washington, D.C. 20461.

Mr. Silawsky can also be reached by phone at area code 202-633-8641.

If you didn't get that address and want it, please see either Mr. Silawsky or myself after the meeting.

Congress gave the Department of Energy control over the Naval Oil Shale Reserves in 1977. DOE has since been investigating the potential to develop a large-scale mine and production facility there as a means of increasing the nation's supply of domestic fuels.

NOSR-1 and 3 were withdrawn for the Navy by executive order in 1916 and 1924 as potential reserves of military fuels. In 1962, Public Law 87-796 gave the Secretary of the Navy the same authority to develop the NOSR's as he had for the Naval Petroleum Reserves. In 1977, Public Law 95-91 transferred the jurisdiction over the Naval Petroleum and Oil Shale Reserves from the Navy to the Department of Energy.

Stemming from the increased awareness of domestic production needs which resulted from the Arab oil embargo of 1973-74, a multi-year predevelopment plan for NOSR-1 and 3 was prepared by the Navy and submitted to Congress. This plan was approved in 1977.

The initial objective of the plan was to assess the oil shale and water resources of NOSR-1 and 3, develop environmental baseline data and determine the most suitable development scenarios for the NOSR-1 and 3 resources. The goal of this 1977 plan was to prepare a master plan for government development of commercial scale facilities on NOSR-1 and 3.

In late 1978, the plan was divided by DOE into two phases. The first is an environmental baseline determination as well as a resource and technology assessment, both to be completed in late 1981. The second is an environmental impact analysis and an environmental impact statement with a requisite supporting preliminary engineering for a site specific commercial-scale facility.

Phases One and Two serve to maintain the momentum and timeliness of all of the development options of leasing, joint ventures or development facilities under any contingencies.

The draft EIS described in this notice will use information developed in Phase One and in DOE's overall oil shale program to discuss the impacts of various policy options to develop NOSR-1 and 3 in Colorado.

The funds to develop the NOSR's under the several policy options considered have not yet been authorized by Congress. The EIS which we are discussing today will be included in any DOE recommendation to Congress for NOSR development.

Currently, there are two major heating, that is, retorting, processes developed by industry to produce oil from shale, surface and modified in situ. Both involve the steps of mining, extraction and upgrading to some degree. Transportation of the shale oil from the site to a refinery market is the last major step.

A 50,000 barrel per day surface retorting facility producing upgraded oil from 30-gallon per-ton -- that's high-grade oil shale -- will requiring the mining and crushing of about 70,000 tons per day of oil shale. About 85 percent of this tonnage must be disposed of on the surface as spent shale. It may be possible, however, to return a large portion of spent shale to the underground rooms.

In the modified in situ process, the underground, in-place process, 20 to 40 percent of each retort column is mined to create voids. The remaining rock is rubbilized and retorted by firing in place. The oil shale -- or the shale oil, rather, is then pumped to the surface.

There are approximately 17 options available for extracting oil from shale. These fall broad into the categories of retorting, solvent processing and bio-leaching.

Retorting, the most widely used method, heats oil shale, either in an above-ground vessel or in situ, to the temperature at which kerogen, the organic material within the ore, is decomposed into gas, condensible oil and a solid residue. The rate of kerogen residue is high at retort temperatures of 900 to 950 degrees Fahrenheit and complete decomposition occurs within a few seconds, or a few minutes. Product characteristics are similar to products obtained from thermal cracking and coking of petroleum.

Upgrading describes on-site methods for improving the flowability and the chemical properties of shale oil and gas. The methods used are commonly practiced in the petroleum refining industry during conversion of petroleum into finished products, such as gasoline and diesel oil, but modified to accommodate the special characteristics of shale oil. A minimum of upgrading is necessary to transport shale oil through unheated pipelines.

The following environmental issues are among those addressed in the draft to EIS. The list is not all inclusive, nor was it intended to be a predetermination of impacts.

The impact issues are:

The effects of the labor markets resulting from the development of options and the effects of the resulting labor immigration on local infrastructures,

2. The effects of the proposed development options of the communities in Garfield and Rio Blanco Counties, Colorado,

3. The effects of NOSR development options on tax basis,

4. The general effects of oil shale mining, storage, disposal and plant runoff on surface and ground water quality and on aquatic ecology,

5. The general effects of the proposed development options on air quality, including the combined effects with other major or planned emission sources in the area,

6. The effects of potential accidents and product releases on water supply and ecology,

7. The effects of each development option and operation on present and future land uses and on terrestrial ecology,

8. The effects of development on local water resources, including the Colorado River,

9. The effects of spent shale disposal, and

10. The effects of transporting the shale oil from the site to a refinery.

For each of the four proposed development policy options, significant economic issues are also addressed in detail. Some of the major issues for each of the options are as follows:

F. For leasing maximum parcel size, royalty terms, lease payment schedules, diligence requirements.

For government-industry joint venture, mix of ownership, investment and payment schedules.

For GOCO ventures, treatment of sales and fee schedules.

For quasi-utility ventures, government definition and control of rates of earnings.

The final EIS will examine and compare the environmental effects of the NOSR development policy options as well as reasonable alternatives to NOSR-1 and 3 developments, and these alternatives include, number one, no action; number two, increased conservation; number three, oil shale development on other lands; number four, enhanced oil recovery; number five, outer continental shelf oil production; number six, coal liquification; number seven, tar sands, and number eight, biomass and alcohol production.

Now, all interested parties have been invited to attend these meetings to submit comments or suggestions in connection with the final EIS. Written comments or suggestions may be submitted in lieu of or in addition to participation at the meeting here today.

Those desiring to submit comments or suggestions to be addressed in the final EIS should submit them to Mr. Silawsky at the address given previously, and, remember, we must have them in hand by November 28th.

Now, those wishing to participate in the hearing process will be able to do so this afternoon. We have two pre-sign-ups, and those of you who wish to give input after those people have been called upon, please indicate by raising your hand when called upon.

This meeting will not be conducted as either an evidentiary or an adversary hearing. Those who choose to make statements may not be cross-examined by other speakers.

The members of the panel may ask the speakers questions necessary to clarify any statements made or positions advocated.

The purpose of the meeting is to give you, the public, the opportunity to participate in the decision-making process. We from DOE are here to listen and to learn.

In order to provide the Department of Energy with as much information as possible and as many views as can reasonably be obtained and to provide interested persons with equitable opportunities to present their views, we have adopted the following guidelines. Speakers will be called on to testify in the order they sign or as they express their intent to speak here by raising their hands when called upon. Should any speaker desire to provide additional information for the record, it may be submitted in writing no later than November 28, 1980. Written comments will be considered and given equal weight with oral comments.

A transcript of the meeting will be retained by DOE and made available for inspection at the Freedom of Information Library, Room GA-152, Forrestal Building, 1000 Independence Avenue, N.W., Washington, D.C. 20585, between the hours of 8:00 a.m. and 4:30 p.m., Monday through Friday.

Upon completion of the final EIS, it will be available at DOE and in the public libraries of Grand Junction and Denver.

Those not desiring to submit comments or suggestions at this time but who would like to receive a copy of the final EIS when it is issued should also notify DOE. Those seeking further information may inquire with Mr. Silawsky.

All discussions, comments and questions submitted to DOE by November 28, 1980, will be carefully considered in the preparation of the environmental impact statement.

We appreciate your interest in the process and welcome you to today's meeting, as well as any future DOE meetings.

I would like now to call upon Lee Brennan to discuss some specific issues of the draft EIS. Lee?

MR. BRENNAN: Thank you, Jack. What I would like to do very briefly is just put the impact statement into the prospective of where it fits into the decision process that we are going through in DOE on what to do with the Naval Oil Shale Reserves, and for anyone who is not familiar with the property, we have the next light is a map which indicates the location of the NOSR's in Colorado, a little to the northwest of Rifle and about 60 miles to the east of Grand Junction.

The programmatic EIS that we are working with here is a fundamental building block in the decision process on how to utilize the Naval Oil Shale Reserves. That process begins with a generic-type analysis of the impacts associated with development, a comparison of those impacts with other alternatives for accomplishing a similar goal, and then through this information we can identify the preferred alternative.

A key part of that analysis is what we are here for today, which is to gather the comments from the public and also the federal, local and state agencies.

Also to be noted, the programmatic EIS deals with an analysis of impacts of the broad policy options. Should there be any action forthcoming out of this analysis in the decision that will come from it, we would then have to move to a site specific environmental impact statement, which would analyze the impacts of the specific project at a specific site.

Now, where this fits into a hypothetical, we have here a hypothetical schedule on a possible scenario that would end with development of the Naval Oil Shale Reserves, the programmatic EIS is in the first part of the predevelopment program, which is right in there, which ends in mid '84. At that point all the information required in the way of technical, environmental, economic and budgetary would be presented up through the executive branch to Congress for their review and approval.

Until congressional approval were received, we would not move past this initial study and analysis phase into the design, which would take us, as we see it, with at least a year for that type of review, into the 1985 and out time frame before we would even begin, we could begin with anything along the lines of a design.

The predevelopment program itself is broken into several major components. Now, we are at the, coming up to the end of what we would consider the first phase of this, which is the decision phase on what should we pursue at the end of -- for the second half, and should we develop the NOSR's; if so, what mechanisms should be utilized.

That will -- that decision at the conclusion of the EIS when it's finalized, a decision package will be presented that will go up through DOE. That decision should be forthcoming somewhere in 1981, and we would then scope the second phase of the predevelopment program around that decision.

The major elements seen here in the way of environmental community impact analysis and engineering cost estimations would be there. The degree and the approach we would take for those elements will be dictated by the decision that comes out within the next year, and that included in that decision is should the NOSR's be developed at all; if so, what would be the best mechanism to do this, leasing, joint venture, a GOCO or whatever.

I hope that provides a little bit of clarity from where the impact statements fit in the scheme of things, and I will turn the meeting back over to Jack, and we can get on with the real business at hand, which is receiving your comments. Thank you.

MR. O'BRIEN: We have two people who have pre-registered for this afternoon. Our first speaker will be Rich Hall of Union Oil.

I will ask you, please, to come up to the microphone on the table. You can sit down, and this way everybody will be able to hear.

MR. HALL: Good afternoon. I am Richard Hall, Assistant Counsel with Union Oil Company of California. I appreciate this opportunity to appear before you and to share our views with respect to the development of the Naval Oil Shale Reserves.

Union Oil Company has been a pioneer in the research and production of shale oil. More than 50 years ago, in the 1920's, Union first began acquiring property in the Parachute Creek area of Garfield County, Colorado. We now own in fee more than 20,000 acres of oil shale lands and have additional claims on approximately the same number of acres.

Part of Union's holdings are to the west and adjacent to United States Naval Oil Shale Reserve No. 1 and just south of Colony's property. The geology and type of shale deposits on Union's property is very similar to that of the Naval Oil Shale Reserve. Union estimates that on its 20,000 acres there is an excess of 1.6 billion barrels of recoverable oil available.

Starting in the early 1940's and continuing into the early 1950's, Union built and operated a small 50-ton-per-day pilot retort at its Los Angeles refinery. From 1955 through '58, Union built and operated a retort in Parachute Creek Valley, which processed up to 1,200 tons of ore per day and producing approximately 800 barrels of shale oil per day.

The company has developed technology for treating the shale ~~dried~~ Derived oil so it can be processed in a crude oil refinery. In the first commercial-scale refining of

Colorado shale oil, over 13,000 barrels of shale oil were successfully processed into gasoline and other products in a refinery near Fruita, Colorado.

In the late 1950's, Union had anticipated commencing the commercial development of its oil shale properties. However, the low prices of world crude oil in the 1960's forced Union to shelve the project. Nevertheless, Union has continued its research and evaluation with respect to shale oil, and on October 21 of this year announced its decision, in anticipation of government financial assistance, to commence construction of a 50,000-barrel-per-day shale oil production facility.

In view of the dramatic increase over the last few years of foreign crude oil prices, the uncertainty surrounding the availability of foreign crude, and the enactment of the Energy Security Act, it is apparent that more and more companies will follow Union's lead and start commercial-scale development and production of shale oil.

While the technology and knowledge for the development of shale oil has been available for some time, it has only recently been economically feasible to develop shale oil on a commercial-sized scale. Therefore, it is anticipated that numerous companies, utilizing many different processes, will simultaneously upgrade their research and development efforts into full-scale commercial projects.

The Department of Energy, in its notice of public hearing on the development policy options with respect to Naval Oil Shale Reserves in Garfield County, stated that there were three decisions to be made with respect to helping attain the President's oil shale production goal of 400,000 barrels per day by 1990. These decisions were: (1) Whether to promote development of oil shale on federal lands, (2) If the decision is to develop federal land, whether to develop the Naval Oil Shale Reserves, and (3) If the decision is to develop those reserves, what institutional and financial mechanisms should be selected.

With respect to the first decision, we believe that the government should promote development of oil shale on federal lands. In doing so, it should seek to have the cooperation and coordinated efforts of all agencies, including, for example, the Department of Interior and EPA, engaged in this effort.

The government should facilitate and expedite the process of leasing the federal lands, it should expeditiously settle existing patent claims, it should encourage land exchanges where necessary for better development, it should promote offsite disposal where necessary, and it should coordinate and expedite the permitting procedures required by EPA and other agencies.

In deciding whether to develop the Naval Oil

Shale Reserves, it is Union's belief that they should not be developed at this time, but that contingency plans should be prepared for their development when appropriate.

At the present time, there are no proven commercial-size facilities existing for the production of oil shale. However, the recent escalation of crude oil prices and the enactment of the Energy Security Act have stimulated several companies, each with differing technological processes, to commence activities for the commercial-scale development.

Union's process is scheduled to be onstream at a commercial production scale of 10,000 barrels per day in 1983. Additional modules will be added to your schedule to produce at a 50,000 barrel-per-day rate in 1987. It may be anticipated that other companies will be following shortly thereafter.

Although Union thinks its process is one of the best, by the year 1990 there should be large-scale commercial development and production of shale oil by several companies using different technologies. It is not known which, if any, of the existing technologies will be the best to utilize to obtain maximum production from the Naval Oil Shale Reserves. However, by 1990, or shortly thereafter, it should be clear which technologies, or a combination thereof, will be best suited both environmentally and technologically for development of the reserves.

Development of the Naval Oil Shale Reserves now might result in the selection of a less than best technology and might divert companies from the development of other oil shale lands. If the government were to utilize the Naval Oil Shale Reserves at this time, it would not contribute to or expedite the President's oil shale production goal of 400,000 barrels per day by 1990.

If and when the decision is made to develop the Naval Oil Shale Reserves, it is considered that the most efficient and best way will be by competitive leasing to private companies. It is anticipated that private industry, with government backing to obtain the necessary financial resources, will have the capability and the expertise for development in the best practical manner. Whether the decision is to await proven technology or proceed immediately, we believe private industry is best able to respond and provide the most timely and efficient development.

In summation, it is recommended that the Naval Oil Shale Reserves not be developed at this time. Instead, all administrative and legislative barriers should be lifted, contingency plans developed and the necessary mechanisms put in place to permit immediate leasing of the Naval Oil Shale Reserves to private companies when needed.

Whether the decision is made to develop these reserves now or later, Union Oil Company is interested in submitting a proposal for development, at least for the retort site at the head of the East Fork of Parachute Creek. This site is adjacent to and compatible with the site we are presently developing in the East Fork of Parachute Creek and can be produced more efficiently in concert with our project rather than independent of it.

Thank you.

MR. O'BRIEN: Thank you, Mr. Hall. Are there any questions from any of the panel?

(There were no questions.)

MR. O'BRIEN: Our second speaker will be Anne Vickery, representing herself as a private citizen.

MS. VICKERY: My name is Anne Vickery. I am speaking as a private citizen. I have been active in the oil shale field since 1974 --

MR. O'BRIEN: Anne, just a moment. Can you all hear back there? Thank you.

MS. VICKERY: -- and have served as Governor Lamm's appointee to the Oil Shale Environmental Advisory Panel from 1977 to 1978.

I would like to compliment DOE on three aspects of the draft. It is short and relatively easy to read. It includes a cycle efficiency chart and it examines conservation as one alternative. I hope this very commendable pattern will be followed in future DOE EIS's.

During the scoping meeting in Denver on February 7, 1980, Mr. Goode indicated that DOE did not anticipate the breadth that people were demanding in the EIS and that DOE considered this to be a relatively minor project. I would like to point out that from the point of view of citizens of the states, this is not a minor project. Rather, it is the biggest project ever to be considered in an EIS in this state.

The biggest mine in the state, Climax Molybdenum, moves about 48,000 tons of raw material a day. It is a gigantic operation. The size of the tailings ponds or slime pits and the size of the whole operation make an indelible impression on anyone who sees it. In contrast, Colony Oil Shale proposes to move 66,000 tons of raw shale a day.

The proposal for NOSR is to move 72,500 tons per day to produce 50,000 barrels a day and to move 290,000 tons a day to produce a 200,000 barrel-a-day operation.

These comparisons should give some understanding of the magnitude of the proposal in contrast to what already exists in Colorado. The resulting air pollution, water consumption, effect on the land and on wildlife and on the surrounding communities are also at a magnitude that is difficult to comprehend.

This EIS is viewed as a tool for assessing these impacts as compared to impacts from other alternatives. The following comments are offered in this light:

(1) On Page 1-3, the statement is made that if there is an absence of meaningful oil shale development in the next year to 18 months, the NOSR proposal may be implemented. 23-1 No criteria are given for defining "meaningful oil shale development". Yet, "meaningful oil shale development" rather than the assessment of alternatives appears to be the crux of the decision.

Section 1502.2 (3) of the CEQ regulations states: "the range of alternatives discussed in environmental impact statements shall encompass those to be considered by the ultimate agency decision maker." Under these circumstances, I request that the criteria, the unpublished criteria, for "meaningful development" be published and that the public be given an opportunity to comment on them and that these comments be included in the final EIS.

23-2 (2) There is confusion over the concept of alternatives. The CEQ regulations state that the alternatives are the heart of the EIS and that the assessment of these alternatives and impacts should provide a clear basis for choice. The NOSR draft states that in a sense the NOSR alternatives are not true alternatives because they may all need to be developed concurrently. That's on Page 1-4.

On Page 3-1, the draft states: "The no-action on NOSR-1 option is implicitly contained in the other alternatives". Colony, which is one of the alternatives, has received all its permits and is being developed to a commercial size operation.

A fair question to ask is, if this one option or alternative is already being developed and the alternative contains implicitly a no-action on NOSR, then why are we here. The same question could be posed for the conservation alternative.

Please clarify the situation and, following the CEQ regulations, provide the public with alternatives which are clearly alternatives to the proposed action.

(3) When an oil shale document appears, one of the first sections the reader looks at is the hydrology section. Page 4-3 states: "The Colorado River will serve as the water supply to the NOSR-1 project. The river is fed by the Green Kampa-Qhite, and Lower Green Rivers, which drain a total of 29,504,000 acres."

23-3

This gives the impression of immense water supplies close at hand, which is in sharp contrast to the meager surface waters available in the Piceance Basin, the distance both horizontal and vertical that the water will have to be pumped out of the Colorado and the fact that the Green does not flow in Colorado.

The misspelling of the Yampa and the White give the impression that either there was no proofreading or that the quality and accuracy of important factors do not matter. The conclusion is that the document really should have been written in Colorado by experts in the areas central to oil shale development.

23-4 (4) Page 3-5 says that when the NOSR operation at 50,000 barrels a day is scaled up to 200,000 barrels a day, integral multiples of the smaller facility will be used for the larger facility. This statement needs to be justified. Experts in the areas of air emissions, socioeconomics, water quality and water quantity may question a linear extrapolation.

23-5 (5) Why, on the emissions charts on Page 3-14 and 3-15 are the NOSR air emissions consistently lower than those for Colony, except for carbon monoxide? This may be because NOSR has not yet gone through the thorough and exact process of obtaining air permits at which time figures and predictions become more realistic. Either the air quality data for NOSR must be justified or the statement should be made that these figures may be changed when the operation seeks air quality permits.

23-6 (6) DOE is to be commended for including the cycle efficiency chart on Page 3-12. This chart is very interesting; it is also very unclear. Appendix C does not help.

One page should be added to Appendix C which lists the factors and the figures that go into the cycle efficiency calculations. These factors for oil shale should include: mining, primary and secondary crushing, transportation of the raw shale, retorting, upgrading, transportation of the spent shale, and transportation of the product to the refinery, emission controls, pumping of the water supply and any electrical demands not included in the above list.

The list should also include the construction, but not the maintenance, of living quarters and community facilities for the oil shale workers and their families, and, finally, the list should include the coal and the construction and maintenance of the coal-fired power plants necessary to supply the purchased electricity.

I cannot stress too strongly that this is the data citizens want to know: How much net energy are we using to produce oil shale, energy that would not be used if oil shale were not produced.

As far as the electrical supply is concerned, Public Service Company of Colorado says it can supply the necessary 100 megawatts required by Colony out of the existing system. For NOSR it is a different matter.

The EPA document "Technological Overview Reports for Eight Shale Oil Recovery Processes" states: "It is expected that some 9,000 KVA net outside power requirements will be needed for mining, crushing retorting, et cetera, in the commercial-module plant." This commercial module will apparently produce from 6,000 to 9,000 barrels a day of shale.

The outside requirements to produce 50,000 or 200,000 barrels a day will be much larger than the identified 9,000 KVA.

Colorado Ute Electric Association will likely service this site. Colorado Ute does not now have the access capacity for oil shale development.

Where will that capacity come from? The answer is that it will come out of the hide of Colorado in the form of a new coal-fired power plant near Delta or near Loma, a new coal mine, Sheridan Enterprises, a new reservoir and extensive power lines. Colorado Ute has already identified a tremendous rate increase for its customers so it can develop these facilities to supply energy for oil shale.

All the energy that goes into developing the outside power requirements for NOSR must be included in the cycle efficiency analysis. The cycle efficiency chart and the final percentages will be changed by this.

But this is a change only on paper. The true energy costs, both in Btu's and in dollars will be there whether or not the chart is changed and whether or not the public is allowed to see them.

By not including these factors, the impression is given that it is desirable that they remain hidden from the public, and this impression does not accurately reflect the current efforts of DOE to do all they can to bring energy issues and data to the attention of the public.

(7) DOE should also be commended for including conservation as an alternative. While conservation may not be the only answer to the present liquid fuels shortage, it may provide a realistic alternative to oil shale development which has widespread impacts and uses a great deal of energy in the process.

23-7 A conservation alternative would be more realistic on a comparative basis if DOE had chosen an example which conserves diesel or jet fuel, which are apparently the preferred end use for shale oil. DOE should consider looking at conservation in diesel trucks and heavy equipment and at conservation in air travel, either commercial, private or military.

23-8 With regard to the conservation example of using lighter weight automobiles, the one that was included in the drafts, this alternative is not an integral part of the document. The criteria for selecting the alternative are geared to an industrial operation.

23-9 In the section "Environmental Impact Comparisons," the statement is made: "Developing any of the technology alternatives discussed above will have adverse effects on the local environments where such development occurs." This is not true for one of the alternatives, which is conservation.

23-8 cont.

The socioeconomic impact from conservation is described as, the primary consequence of saving 50,000 barrels a day is a 0.6 decrease in the amount of gasoline pumped across the nation. This section should mention the tremendous savings in energy, in money and in personal upheaval which occurs when jobs are created on the spot, such as producing lighter weight cars in Detroit, as compared to relocating people and creating new towns.

In other words, the conservation alternative has not been worked into the fabric of the draft. This alternative, on every account, is highly desirable and should become a more central part of the document.

In conclusion, I would like to go back to the original point. This proposal has immense significance for Colorado. DOE apparently has a budget of just under $30,000,000 of taxpayers' funds to reach the point of completing a master development plan. With a budget of that amount and a proposal of such magnitude, it is worth doing the preliminary assessment as to the need for the project very carefully.

Please analyze the cycle efficiency carefully with particular attention to the factors which are missing in the draft. Please look closely at more realistic conservation alternatives Please consult closely with those people in Colorado who are experts in all of the areas that oil shale impacts.

Above all, please keep in mind that there could be a lot of conservation projects and solar energy projects for $30,000,000. There must be accurate, reasonable justification for the NOSR operation before it proceeds.

MR. O'BRIEN: Thank you very much, Anne. Are there any questions from the panel?

(There were no questions.)

MR. O'BRIEN: Thank you. Is there anybody else who at this point would like to make a statement or make a contribution to these proceedings? Anybody at all?

(No response.)

We were scheduled to run until 5:00 o'clock. That's two more hours. We will keep the meeting open for the next hour or so to see if anybody does come and want to make a comment.

If any of you in the meantime would like to make a comment on the record, please indicate either to any of the panel or to myself, and we will see that you get that opportunity.

We will be meeting again tonight at 7:00 o'clock in the same room, and I thank you all for coming, and, again, if you have any input for us, we would like to have it.

The meeting will stand down temporarily.

(The afternoon session was concluded.)

* * * *

REPORTERS' CERTIFICATE

I, JUDITH WALLIS, Certified Shorthand Reporter, certify that the foregoing is a true and accurate transcription of my stenotype notes taken at the time and place aforementioned.

Dated this 8th day of December, 1980.

Judith Wallis, CSR

RESPONSE TO SET 23

23-1 Refer to the response to comments 3-5 and 17-4.

23-2 The selection of alternatives for programmatic comparison is a real issue when viewed from a national energy viewpoint. However, the programmatic EIS is basically an environmental document, and the liquid fuel alternatives selected for environmental impact comparison are congruent with the CEQ guidelines. The use of the Colony project to represent the alternative of oil shale development on other land is considered a suitable representation for environmental impacts. The fact that the Colony project is moving closer to development does not invalidate its ability to represent that alternative for environmental comparison purposes. The same argument applies to all the other alternatives, each of which is represented by a specific case in order to generate numerical results for comparison.

23-3 The flow of the Colorado varies considerably by season. Competing water uses, including NOSR, other energy projects, and agriculture, will be permitted to use this resource only in accordance with state water rights laws. The mispelling of the Yampa and White Rivers has been corrected.

23-4 See response to comment 3-6.

23-5 Refer to the response to comment 3-10.

23-6 Refer to the response to comment 3-8.

23-7 Refer to the response to comment 2-4.

23-8A It would be very difficult to postulate an industrial case which would conserve 50,000 or 200,000 BPD of fuel. Therefore, the conservation alternative was based on a product of the subject energy technologies--transportation fuel. See response to comment 5-1G.

23-8B Savings in energy, money and personal upheaval resulting from creation of new jobs were not considered in the conservation case for reasons discussed in response to comment 2-5.

23-9 The general statement that technology alternatives will have adverse local effects has been modified to point out that conservation will have a beneficial effect. This revision is consistent with statements elsewhere in the text.

PUBLIC HEARINGS
For the
Draft Environmental Impact Statement
Development Policy Options
Naval Oil Shale Reserves
Garfield County, Colorado

November 20, 1980, 7:00 p.m.
Federal Building, Room 239
19th and Stout Streets
Denver, Colorado

APPEARANCES:

Jack O'Brien
Lee Brennan
William Goode
Don Silawsky
Michael Fosdick

PROCEEDINGS

MR. O'BRIEN: Good evening and welcome. I will open at this point our evening meeting, a public hearing on the environmental impact statement for considering the policies in conjunction with the development of oil share or Naval oil shale reserves one and three.

My name is Jack O'Brien, I am the moderator for this meeting. I am also the regional coordinator for environment for DOE, and we have a panel tonight consisting of Lee Brennan, Deputy Director of the Office of Naval Petroleum and Oil Shale Reserve; Bill Goode, Environmentalist, Office of the Assistant Secretary for Resource Applications; Don Silawsky, Environmentalist for the Naval Oil Shale Reserves, and Mike Fosdick, Director of Engineering for the Naval Petroleum and Oil Shale Reserves in Casper, Wyoming.

Instead of going through a tremendous amount of background material tonight, I think those of you who are here are aware of what we are trying to do on the NOSR. We are looking at the development of a draft environmental impact statement in accordance with the National Environmental Policy Act for assessing the impact of proposed policy options to develop the 55,000 acre Naval Oil Shale Reserves.

Those policy options include (A) Leasing large parcels to industry, (B) Joint government/industry ventures, (C) Government-owned, contractor-operated GOCO centures, and

(D) quasi-utility ventures.

Of course, the law requires the President and Congress to approve any action that the Department of Energy may take in connection with the reserves, but the public has been invited to submit written comments or suggestions for consideration by the DOE in preparation of the final EIS, and that is why we are here tonight.

We will do this very informally. I will ask Lee to give any comments he wishes to on the Naval Oil Shale Reserves.

If any of you have any further questions on background, the panel or myself will be glad to answer those questions, but we prefer to get to your comments. This is not an evidentiary or an adversary hearing tonight. We don't anticipate any questioning of people who are making presentations.

The panel may ask questions just for clarification to make sure that we understand what you are saying, what positions you are advocating, for purposes of clarity.

If no one has any objections, I will turn it over to Lee Brennan to give you some little background, as he thinks is necessary, and then we will proceed with your testimony. If there are no objections we will proceed on that basis.

MR. BRENNAN: Very briefly, Naval Oil Shale Reserves were set aside in early 1900 as a supply of reserves for the national defense. They lay dormant, with the only activity being the Bureau of Mines.

There was some activities in the thirties and fifties to assess the reserves, and then with the Arab Oil Embargo and the things that came out of that, the understanding of the dependence on foreign oil, it was decided to take a look and to bring the naval reserves in Wyoming and California up to a state where they could be turned on immediately to production and development programs.

Again, at the same time it was decided to do the predevelopment and analysis work on the Naval Oil Shale Reserves, and a predevelopment program was developed, submitted to Congress and approved by Congrees in 1977.

The idea of that plan was to perform the necessary engineering, environmental, economic study, to lay the groundwork for future development.

Now with this draft program EIS we are nearing the end of what we would consider phase one of that predevelopment program, and this is a decision point, as to what to do from here with the NOSRs. The programmatic EIS forms one of the building blocks of that decision, and will be used with other data to make a decision whether they will be developed at all, and if so what would be the best mechanism to do that.

A GOCO, going all the way from the GOCO to merely leasing it out, or the no action alternative.

After a decision is made, which will probably take most of 1981, it would come out somewhere possibly by the end of fiscal 1981; we would then move into the second phase of development work, which would be scoped around that decision, and would probably be a site-specific environmental impact statement addressing this specific project, this specific financing mechanism, et cetera, that was proposed for development. If a development mechanism was chosen over the next year.

That's where we are at right now. Should an active role be sought, some form of development, we will probably be ready to send all of the budget and technical and environmental information by the executive branch to Congress, by sometime in 1984, and we would anticipate at least a year or so in review through those channels, so that would not kick off anything more active in this study phase until at least late 1985.

We would probably not get into the budget cycle until 1987.

So if there are any more questions on background I would be glad to discuss them.

UNIDENTIFIED SPEAKER: What budget cycle is that again?

MR. BRENNAN: I would think at the present, the way we are moving now, we would not be ready to put any development -- if there were any big dollars in the way of development -- prior to the 1986 budget cycle. Budget cycles run about 20 months ahead.

MR. O'BRIEN: Any other comments that any member of the panel would care to make at this point?

In order to provide the Department of Energy with as much information as possible, with as many views as can reasonably be obtained,to provide interested persons equal opportunities to express their views, we will use the following guidelines: speakers will be identified as they express their intent to speak here tonight by raising their hands, and should any speaker decide to provide any additional information for the record, it may be submitted in writing no later that November 28, 1980.

Written comments will be considered and given equal weight as the oral comments, and the transcript of the proceeding will be available and maintained by the DOE for inspection at the Freedom of Information Library, Room A152, Forest Hall Building, 1000 Independence Avenue West, Washington, D.C., between the hours of eight and four p.m. Monday through Friday.

Upon completion of the final EIS it will be available at DOE and in the public libraries at Grand Junction and Denver.

Now if anybody here wishes to make further comments other than tonight, any written comments, they should contact Don Silawsky, Environmental Project Manager of the Naval Program and Oil Shale Reserves. I will read the address if anybody wants it.

UNIDENTIFIED SPEAKER: Including spelling the name.

MR. O'BRIEN: Don Silawsky, S-i-l-a-w-s-k-y, Environmental Project Manager, Naval Petroleum and Oil Shale Reserves, U.S. Department of Energy, 12th and Pennsylvania North west, mail code RA-3344, Washington, D.C. 20461.

Don can also be reached by phone, area code 202, 633-8641.

Now in case anybody wants a copy of the final EIS when it is issued you should also contact Don for that.

UNIDENTIFIED SPEAKER: Aren't we going to automatically receive them?

MR. SILAWSKY: Did you request a copy of the draft?

UNIDENTIFIED SPEAKER: No.

MR. SILAWSKY: Then you won't be automatically sent a copy of the final.

MR. BRENNAN: Did you get a copy of the draft?

UNIDENTIFIED SPEAKER: Yes.

MR. BRENNAN: Then you would get a copy.

MR. O'BRIEN: If you want to insure you get a copy of the final EIS, contact Don and make sure about that.

At this point I would like to take your input. The DOE is here to listen and learn, and we would like to start from the front of the room. I think Kevin Markey, Friends of the Earch. Do you have a statement you would like to make?

MR. MARKEY: I will raise my hand, since the rules state that I should raise my hand.

MR. O'BRIEN: K-e-v-i-n, M-a-r-k-e-y.

MR. MARKEY: My name is Kevin Markey, I am the Colorado representative for Friends of the Earth. Friends of the Earch appreciates this opportunity to speak to the DOE concerning the Naval Oil Shale Reserves and their possible development.

These are preliminary comments and we will supplement them with a written statement some time in the next week.

24-1(A) The objectives of NOSR policy to provide additional leased land for private development is based on the same false premises on which the Bureau of Land Management's new program is based; that resource availability will result in its development. Particularly if NOSR land is leased as a backup for private efforts, which has always failed, chances are that DOE will only double its chances of failure, rather than really achieving shale development.

The reason we are concerned about this type of contingency leasing is simple: even if no development occurs, the public and the Department of Energy lose control of the resources. If and when circumstances might ultimately stimulate private development, private and leased land is then developed all of a sudden, all at once, without regarding cumulative effects or coordinated scheduling.

24-1(B)

Related to this is the need for the Department of Energy to define at this time the circumstances, conditions and criteria by which private industry's success or failure is judged. In the EIS DOE states that it proposes NOSR development if there is, "an absence of meaningful private oil shale development during the next year to 18 months."

What does this mean? We would suggest there is already meaningful development leading to the production of more than 400,000 barrels per day. If DOE believes construction of commercial scale facilities totalling 400,000 barrels per day is necessary by the end of that 18 month period, we would suggest that such a criteria is not only unobtainable, but more important, unnecessary to achieve those goals by 1987 and 1992.

It is crucial that DOE establish publicly a yardstick ahead of time. If not it will be too easy for the agency to change its criteria internally depending upon what circumstances demand.

For example, the Department of the Interior has consistently claimed that the prototype program was a big success. That is, until it wished to justify additional prototype leasing. Suddenly, judged against an impossible goal, the testing of most major technologies, DOI pronounced their prototype program a dismal failure, in order to justify two new leases to test technology.

Well, of course "dismal failure" may be exaggerating DOI's exact words, which were "qualified success," but not its intent.

It was quite clear that it wanted everyone to feel that the prototype program was a dismal failure in terms of testing a diversity of new technologies.

It would be helpful, since this EIS will be input into DOE or Congressional decisions, to proceed further to assess the likelihood at this point of achieving various goals without NOSR development.

One DOE assessment submitted to the Department of the Interior during considerating of new leasing by Interior indicated 400,000 barrel per day production could be reached by 1990 without leasing. That assessment was based on very conservative assumptions, and came before announcements by Chevron and Union to expand plans for production.

Every time DOE wants something it seems it raises the spectre that not obtaining its wish, whether it be new leasing, off-tract disposal, weakening the Clean Air Act, establishing the Energy Mobilization Board, will be a barrier to obtaining synfuels production.

24-1(C)

It is time for the DOE to come out of the closet and submit itself to public scrutiny. The need for NOSR development must be assessed. The no action alternative must be assessed as to whether it can achieve national policy goals. This is required, by the way, by NROC v. Hughes. Thus DOE must include an assessment of how much production will be achieved without NOSR or other actions.

24-1(D)

Obviously this analysis and any proposed criteria for judging success or failure of industrial development, private development, or proceeding with NOSR, must be subject to comment to the final. We suggest issuance of a draft supplement for comments on these issues be issued prior to inclusion in the final.

24-2(A)

Also DOE wants a sign by the end of 18 months as to what the future holds for oil shale development in the private sector. We suggest that this is a premature date. DOE has until 1985 to observe private industry's progress before it must initiate a program, if private efforts fail, if it continues environmental baseline and predevelopment preparations.

24-2(B)

In its discussion of the criteria for proceeding with the no action option, DOE reveals its bias toward oil shale.

First of all DOE will do everything necessary, even establish a contingency leasing program under NOSR for oil shale, but also if the other options, conservation, OCS et cetera are not viable, DOE intends to go with NOSR development.

Even if we do not give the other options the same treatment as shale, last ditch programs to supplement existing federal incentives for these other phases of existing programs are not sufficient. We suggest that such criteria be eliminated.

24-2(C)

With respect to the technical analysis and comparisons, we see several problems. First of all DOE assumes that there will be several economies in proceeding to 200,000 barrels per day, especially in the area of socio-economic impact. Even assuming the extended construction program proposed in that alternative, we cannot agree.

As OTA andothers have pointed out, the greater and faster the development in the Piceance Basin, the greater the social impacts, measured exponentially.

24-2(D)

DOE also suggests that there will be no environmental advantages with GOCO, utility-joint-venture or other modes of development with high federal involvement. We again disagree. Especially where private development has failed environmental control would be higher with greater federal involvement, which offsets the cost cutting effects of competitiv strictly private development.

Federal involvement, with adequate public scrutiny involvement could also set higher standards for environmental controls. This is what might happen theoretically. We don't have much faith in DOEs record to date, whether it concerns cleaning up some fire or reporting accurately what is happening at the SRC-2 plant. However, theoretically these options could produce greater public good.

24-2(E)

There is no basis in fact for the EIS' judgement that NOSR air emissions will be lower than those on other oil shale lands. This is quite crucial. The comparisons in chapter three and elsewhere which seem to show this effect are an artifact of a faulty methodology, which was used to estimate the other oil shale emissions with the emissions from the entire industry which were used to estimate NOSR emissions.

If you look at three on page C-3 you will find that the basis for the NOSR emissions are other industry estimates, but that doesn't even make sense. When you compare those NOSR emission estimates they don't gibe with other industry data. I could put this up on the board if this ends up confusing anybody. I have converted all of these things on a pound per barrel number, just to make it a little easier to compare, and I have compared SO_2 particulate matter and nitrogen oxides for NOSR. For example, under sulfur dioxide there is 04 pounds per barrel. The other shale, the Colony, is a .14. However, industry ranges run from .13 and .72. The NOSR is significantly lower than other industry estimates, and the lowest industry estimate -- to bring this up to date, the industr ranges were based upon compilations made by the Office of Technological Assessment, and basically shows those which were available in various PSD applications or permits. To bring it up to date the lower end of the range is now .10, but that is the absolute lowest that anybody has ever seen, and the .04 has no basis in reality.

24-3 For particulate matter NOSR is .12, other shale, Colony, is .4. However, industry ranges actually run between .09 and .18. Somehow Colony got screwed up there. In fact, Colony's permit indicates a .12 pounds per barrel of particulate matter, which is actually identical to your NOSR estimate.

For NOX NOSR is .44. Other shale, in the EIS, is reported to be .90, but the industry ranges actually run between .26 and 1.68.

So we suggest directing the analysis or eliminating the type of analysis which is present, to indicate actual per barrels all over there.

24-4 Let's see; in terms of socio-economic, again the socio-economic differences between the two different shale scenarios is basically a result of the artifact of the methodology. You are comparing sort of a set of facts judgement on the basis of what the industry averages are with one plant.

24-5 With respect to shale versus biomass, it is indicated that biomass will have significant employment and population affects. However, and this is somewhat indicated in the text but it is not quite clear enough, the distribution of that population will be diffuse and spread out over large areas, and a number of different communities.

Given that it is going to be spread out among those communities, in fact in an area which needs additional employment and needs additional industrial development, it may be beneficial rather than harmful, which of course is the sort of assumption that one gives to socio-economic impacts in Colorado.

Concentrating all these folks, even if they are fewer in number, in one place, will be harmful. In Illinois, in the corn belt, whatever, that might be beneficial.

24-6 In terms of air emissions, the comparison of shale versus biomass is quite dramatic, but that again depends on some unusual sorts of assumptions.

The shale numbers which are indicated, the .14 for example, assumes a 99.6 percent sulfur removal. You have assumed 90 percent SO_2 cleanup with the sulfur emissions from Illinois Coal. If you actually look at the uncontrolled emissions for oil shale, they range between 240 and 384 tons per day. Again, that is the compilation of the Office of Technology Assessment.

The control of biomass emissions, based on the NOSR EIS is 510 tons per day, so they are a little bit closer in terms of uncontrol, and if you place a 95 percent emission control on each of those, we presumably will be capable, if you assume in both cases the application of new gas to sulfurization, you are going to get much closer controlled emissions.

In the context of the regional dispersion, biomass probably has fewer problems, even if you assume a higher emission rate, and this still assumes that you are going to use pretty high-sulfur coal in the heat cores. In the ethanol conversion process, finally, we point out that shale seems to have gotten an awful lot of favors; $3 per barrel tax credits, 20% business investment tax credit, defense production authority, the synfuels prototype program expansion, favorable environmental regulatory decisions, and I could take the list on and on, and I did in my scoping comments.

Does oil shale need more? Even on a contingency basis we think not. If industry can't develop the shale with all these favors, it is time to bite the bullet and say no, and not just give industry another favor.

MR. O'BRIEN: Kevin, you do intend to present a written statement?

MR. MARKEY: Yes.

MR. O'BRIEN: That should be sent to Mr. Silawsky.

MR. BRENNAN: On the 1985, just to clarify, where did you evolve that number, that date?

MR. MARKEY: Basically by a look at the five-year construction period for surface retorting and undergound mining. That's based on Union and Colony's estimated being constructed by 1982. Give yourself an additional two-year lead time for all of the preliminaries, including lease sales, or whatever sort of arrangements you would negotiate, if you have done the baseline work and all the preliminaries leading up to that. That was the other assumption.

MR. BRENNAN: You are assuming all the environmental work would be done?

MR. MARKEY: Right.

MR. O'BRIEN: That question was from Mr. Brennan. Any other questions from the panel?

Is there anybody else that would like to present a statement at this point? Would you please come forward and identify yourself, sir, or you can speak from there as long as we can hear you.

MR. CUNNINGHAM: Curt Cunningham. I am representing here the Rocky Mountain Chapter of the Sierra Club. I do have written comments that will be sent in, but I will summarize them to some extent now.

The following comments on the Draft Programmatic EIS for the Naval Oil Shale Reserve in Gaffield, County, Colorado, are made on behalf of the Rocky Mountain Chapter of the Sierra Club. Our organization has 3,000 members in Colorado, many of whom have interests that would be adversely affected by proposed NOSR developments.

It is not easy for us to state our attitudes towards this DEIS precisely. On the one hand, the basic philosophy of approach to this impact analysis of a major

Federal synthetic fuel program has some commendable aspects. In the process of examining how X barrels per day of liquid fuel are to be produced, the Department of Energy has taken two steps back and has gotten a much broader perspective on the various possible means to that end.

Sierra Club people and other environmentalists have been urging such a broad-guaged approach for a long time. The DEIS is particularly valuable because it outlines the extreme impacts and differences in impacts between the different alternatives. It is heartening to see that the results match out expectations; i.e. coal liquififaction has the worst impacts, shale and enhanced oil extraction somewhat less bad, but the best of all by far is conservation. Had the costs to the ultimate consumer been compared for the aternatives, conservation would have appeared in an even more favorable light, and the comparisons among the others would have been very illuminating.

24-7 The lack of such an economic impact statement on the consumers' pocketbook is, in our opinion, a substantial flaw that we urge be corrected in the Final EIS. Not only comsumers as such, but also in their role as taxpayers and public officials would benefit from having such comparative information available to them.

Moreover, it seems only just, considering the hundreds of millions of dollars, even billions of dollars of public monies which have been or will be used to prop up synfuels operations.

24-8 On the other hand, we must criticize the DEIS because its aim has evidently been far more ambitious than its means. That is, the analysis is in places sloppy, superficial, or wrong. Evidence for this statement is indirect, consisting of the prior assumptions or misstatements discussed below:

(1) We see problems with the analysis of the biomas alternative. First, it seems more likely to us that during the time frame of possible NOSR development, 50,000 barrels a day of oil equivalent would be produced more economically, and practically on the farm, using crop residues, not coal, as the distillation fuel.

Ethanol produced would displace fuel otherwise purchased by the farmer. We perceive more support on the part of farmers now for a system like this, rather than the centralized facility studied by DOE. 24-9 Moreover, the technology assumed in the DEIS for ethanol production is swiftly becoming obsolete. Much less energy intensive ways than complete distillation will soon be available; for example, modified corn starch has recently been demonstrated to remove water efficiently from partly distilled feedstock. Two recent papers in Science magazine come to mind. Of course, this is not perhaps at the engineering stage, but the point is that those are pretty simple approaches, and they seem to work fairly well.

Less energy required for distillation means smaller ancillary impacts.

24-10 However, even if one goes with the conventional technology, projected emissions and inputs are misstated. For example Figure 3-4, page 3-13 compares SO_2 emissions for the technology alternatives. The 16,800 tons per day figure for biomass must be the uncontrolled emission rate, whereas the other figures are for controlled emissions. The proper value is 1680, which is ten percent.

24-11 Table 5-10, page 5-38. The heading of column two is incorrect. The carbon dioxide emission rate is incorrect. Even if coal were 100% carbon, 4,155 tons per day, only 15200 tons per day of CO_2. The figure for uncontrolled SO_2 emission rate seems too low because it assumes only 1.2% sulfur content for eastern coal. I don't know whether that is correct or not, but with my superficial familiarity with eastern coal sulfur dioxide content, it seems a bit low.

24-12(A) On page C-23 again, the SO_2 emission figure should be 5.1 tons per day, not 51 tons per day, because 90% control has been factored in.

The other aspect of the biomass problem is the use of water, and if anybody can enlighten me on that I would
24-12(B) appreciate it. Page 3-17, figure 3-5 lists 110,000 acre feet per year for biomass operations, comparative to roughly a tenth of that for a lot of the others. Where is all this water going?

Is the use comsumptive? I would like to see a clearer rationale for this figure.

We feel these four problem statements make biomass seem much more damaging than we believe it would be. In some ways it seems to be just a simple error, but in other ways, with respect to the water, it is a question.

24-13 We have the same problem as mentioned before for the emission figure comparisons for the proposed NOSR operations, and Colony seems way off. NOSR is consistently lower than Colony by factors of 2-4, yet retorting processes and pollution control methods should be similar. We are wondering whether DOE has come upon some great new advance in pollution control technology that no one else is aware of. We think that those figures should be either justified pretty clearly or changed to avoid the suspicion that the deck is being stacked on behalf of NOSR development.

24-14 The other questionable figure to us has to do with economic impacts. On page 3-38, figure 3-10 a 200,000 barrel per day operation is projected to cost local government about 32 million for oil shale development, for developing the economic interstructure of local communities, et cetera. However, the state estimates for local needs are several times greater than this.

For example, Governor Lamm has stated publicly that a 400,000 barrel per day industry would involve capital for services expenditures of about half a billion dollars. Using the 32 million dollars figure and projecting to 400,000 gives a figure which I think is suspiciously close to the present and arguably inadequate size of the state oil shale trust fund. Who is right? Has the state has its own input? Perhaps they are exagerating too.

24-15 A final and relatively minor point; page 4-7 states the southern Piceance Basin has a low seismic potential, but if memory serves me correctly, Grand Junction and environs experiences fairly frequent but small earthquakes. That seems to stick in my mind. I am not sure about that fact.

24-16 Other general comments: On page B-8 the domestic inflation rate and the world oil price projections seem too low to us, but because these two quantities might change the comparison of alternatives, we suggest that some sort of a sensitivity analysis be done on these and other variables in economics, but we suspect that higher inflation rates and oil prices would make conservation look even better. This comparison emphasizes to us once again the importance of calculating the total cost to the consumer on the various alternatives.

24-17 On page 5-67 the statement is made that rural energy developments do not impact urban areas in the region. This is not correct for oil shale. Much of the responsibility for the Front Range's socially and environmentally disruptive growth can be laid at the feet of energy development; until now not metals, oil, gas coal. But energy development in rural areas does impact on the Denver area.

This unfortunate trend will be exacerbated by massive oil shale development. A similar statement can be made for quasi-urbanized areas around Grand Junction. All the local communities, when they ask for money for treatment facilities, say it is oil shale or oil and gas, so these things have their impact far away.

24-18 On page 5-51 just a general question; are socio-economic impacts discussed here truly additive between different scenarios of a given technology, or between various levels of different technologies, which is the practical case?

It seems to be implied here and elsewhere in the draft of the Environmental Impact Statement.

We feel that non-linearity or non-additivity of impact is more likely. In other words, at some point the development becomes insufferable to everybody, such as we find in Rock Springs and other great examples.

We hope that these comments are useful and that the final EIS will be improved, in the factual statements at least, if not in more subjective aspects of the draft.

Thank you very much.

MR. O'BRIEN: You will be giving us a written summary of your statement?

Are there any questions from any of the panel members?

Thanks once again for the input. Are there any other statements? Is there anybody else who would like to make a statement at this point? Again we are scheduled to go for a substantial period of time, so we will stand down for a brief period of time. If anybody does come up with a statement, or if somebody in the audience decides they would like to make a statement, please feel free to.

Again, we solicit from you written statements. They will be given equal weight with any testimony we receive.

We appreciate your coming tonight, and thank you very much.

(The hearing was recessed at 7:50 p.m.)

* * *

REPORTERS' CERTIFICATE

I, Edith M. Moore, Certified Shorthand Reporter, certify that the foregoing is a true and accurate transcription of my stenotype notes taken at the time and place aforementioned.

Dated this 15th day of December, 1980.

Edith M. Moore, CSR

RESPONSE SET 24

24-1A through D Refer to the response to comment 2-7 and 18-3.

24-2A through E These comments have been dealt with in response set 18.

24-3 Colony emissions figures were taken from the Colony EIS. Colony PSD data are used in the final EIS.

24-4 Refer to the response to comment 18-5.

24-5 The discussion on page 3-22, 2nd paragraph, points out that dispersion of the 14 plants will result in reduced population increases in a given area. The socioeconomic analysis of biomass was revised.

24-6 Refer to the response to comments 18-23 and 16-4.

24-7 While comparative information on the relative consumer costs of energy alternatives would certainly be a useful decision-making tool, such an economic impact statement is beyond the scope of this document.

24-8 See response to comment 18-16.

24-9 See response to comment 16-3.

24-10 See response to comment 16-4.

24-11 See response to comment 16-4.

24-12 See response to comment 16-4

24-13 See response to comment 16-6.

24-14 See response to comment 16-7.

24-15 See responses to comments 12-12 and 16-8.

24-16 See response to comment 16-9.

24-17 See response to comment 16-10.

24-18 See response to comment 16-11.

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